(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
23 February 2006 (23.02.2006)

PCT

(10) International Publication Number
WO 2006/019901 A2

(51) International Patent Classification:
G01V 11/00 (2006.01)

(21) International Application Number:
PCT/US2005/024975

(22) International Filing Date: 14 July 2005 (14.07.2005)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
10/892,011 15 July 2004 (15.07.2004) US

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

(72) Inventors: **HASSAN, Gamal, A.**; 16611 Creeksouth Road, Houston, TX 77068 (US). **KURKOSKI, Philip, L.**; 4914 Middle Falls Drive, Humble, TX 77345 (US).

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

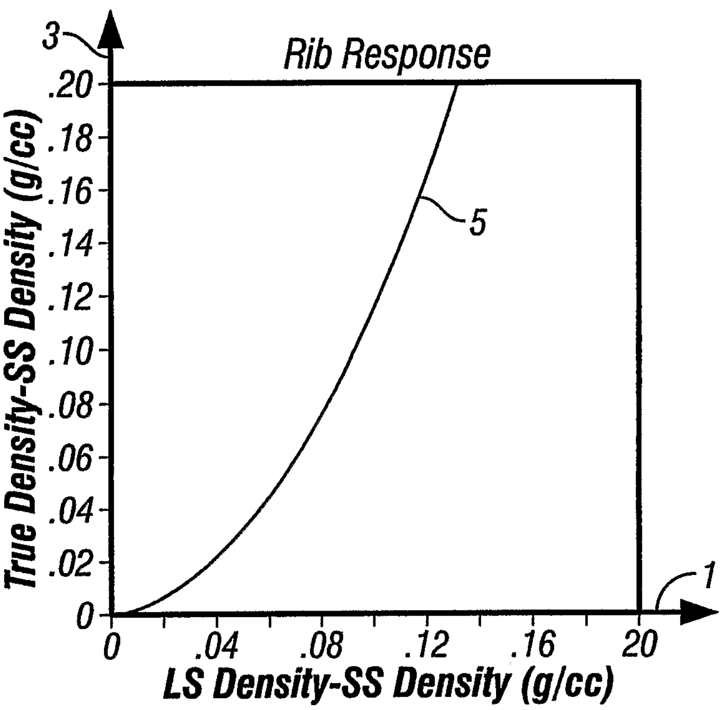
(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BW, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NA, NG, 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, US, UZ, VC, VN, YU, 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, HU, IE, IS, IT, LT, LU, LV, 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).

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.

(54) Title: APPARENT DIP ANGLE CALCULATION AND IMAGE COMPRESSION BASED ON REGION OF INTEREST



(57) Abstract: The present invention provides a method and apparatus for logging an earth formation and acquiring subsurface information wherein a logging tool is conveyed in borehole to obtain parameters of interest. The parameters of interest obtained may be density, acoustic, magnetic or electrical values as known in the art. The parameters of interest may be transmitted to the surface at a plurality of resolutions using a multi-resolution image compression method. Parameters of interest are formed into a plurality of Cost Functions from which Regions of Interest are determined to resolve characteristics of the Features of interest within the Regions. Feature characteristics may be determined to obtain time or depth positions of bed boundaries and borehole Dip Angle relative to subsurface structures, as well borehole and subsurface structure orientation. Characteristics of the Features include time, depth, and geometries of the subsurface such as structural dip, thickness, and lithologies.

WO 2006/019901 A2

TITLE: APPARENT DIP ANGLE CALCULATION AND IMAGE COMPRESSION BASED ON REGION OF INTEREST

INVENTORS: Gamal Hassan, Houston, Texas; Phil Kurkoski, Houston, Texas

[001] Field of the Invention: This invention relates generally to borehole logging apparatus for use during drilling operations and methods for acquiring subsurface measurements and communicating the data to the surface. More particularly, this invention relates to subsurface feature identification and efficient transmission of imaging data and subsurface structure data in real time in a measurement-while-drilling (MWD) tool.

[002] Background of the Art: Oil well logging has been known for many years and provides an oil and gas well driller with information about the particular earth formation being drilled. In conventional oil well logging, after a well has been drilled, a probe known as a sonde is lowered into the borehole and used to determine some characteristic of the formations which the well has traversed. The probe is typically a hermetically sealed steel cylinder which hangs at the end of a long cable which gives mechanical support to the sonde and provides power to the instrumentation inside the sonde. The cable also provides communication channels for sending information up to the surface. It thus becomes possible to measure some parameter of the earth's formations as a function of depth, that is, while the sonde is being pulled uphole. Such "wireline" measurements are normally done in real time (however, these measurements are taken long after the actual drilling has taken place).

[003] A wireline sonde usually transmits energy into the formation as well as a suitable receiver for detecting the same energy returning from the formation to provide acquisition of a parameter of interest. As is well known in this art, these parameters of interest include electrical resistivity, acoustic energy, or nuclear measurements which directly or indirectly give information on subsurface densities, reflectances, boundaries, fluids and lithologies among many others.

[004] Examples of prior art wireline density devices are disclosed in U. S. Pat. Nos. 3,202,822, 3,321,625, 3,846,631, 3,858,037, 3,864,569 and 4, 628,202. Wireline formation evaluation tools (such as gamma ray density tools) have many drawbacks

and disadvantages including loss of drilling time, the expense and delay involved in tripping the drillstring so as to enable the wireline to be lowered into the borehole and both the build up of a substantial mud cake and invasion of the formation by the drilling fluids during the time period between drilling and taking measurements. An improvement over these prior art techniques is the art of measurement-while-drilling (MWD) in which many of the characteristics of the formation are determined substantially contemporaneously with the drilling of the borehole.

[005] Measurement-while-drilling (MWD) logging either partly or totally eliminates the necessity of interrupting the drilling operation to remove the drillstring from the hole in order to make the necessary measurements obtainable by wireline techniques. In addition to the ability to log the characteristics of the formation through which the drill bit is passing, this information on a real time basis provides substantial safety and logistical advantages for the drilling operation.

[006] One potential problem with MWD logging tools is that the measurements are typically made while the tool is rotating. Since the measurements are made shortly after the drillbit has drilled the borehole, washouts are less of a problem than in wireline logging. Nevertheless, there can be some variations in the spacing between the logging tool and the borehole wall ("standoff") with azimuth. Nuclear measurements are particularly degraded by large standoffs due to the scattering produced by borehole fluids between the tool and the formation.

[007] U.S. Pat. No. 5,397,893 to Minette, the contents of which are fully incorporated herein by reference, teaches a method for analyzing data from a MWD formation evaluation logging tool which compensates for rotation of the logging tool (along with the rest of the drillstring) during measurement periods. The density measurement is combined with the measurement from a borehole caliper, preferably an acoustic caliper. The acoustic caliper continuously measures the standoff as the tool is rotating around the borehole. If the caliper is aligned with the density source and detectors, this gives a determination of the standoff in front of the detectors at any given time. This information is used to separate the density data into a number of bins based on the amount of standoff. After a pre-set time interval, the density measurement can then be made. The first step in this process is for short space (SS) and long space (LS) densities to be calculated from the data in each bin. Then, these density measurements are combined in a manner that minimizes the total error in the density calculation. This correction is applied using the "spine and ribs" algorithm and graphs such as that shown in **Figure 1**. In the figure, the abscissa **1** is the difference between the LS and SS densities while the ordinate **3** is the correction that is applied to the LS density to give a corrected density using the curve **5**.

[008] U.S. Pat. No. 5,513,528 to Holenka et al teaches a method and apparatus for measuring formation characteristics as a function of azimuth about the borehole. The measurement apparatus includes a logging while drilling tool which turns in the borehole while drilling. The down vector of the tool is derived first by determining an angle ϕ between a vector to the earth's north magnetic pole, as referenced to the cross sectional plane of a measuring while drilling (MWD) tool and a gravity down vector as referenced in the plane. The logging while drilling (LWD) tool includes magnetometers and accelerometers placed orthogonally in a cross-sectional plane. Using the magnetometers and/or accelerometer measurements, the toolface angle can usually be determined. The angle ϕ is transmitted to the LWD tool thereby allowing a continuous determination of the gravity down position in the LWD tool. Quadrants, that is, angular distance segments, are measured from the down vector. Referring to **Figure 2** (which is Holenka et al's **FIG. 10B** illustrating a LWD tool **100** rotating in an inclined borehole **12**), an assumption is made that the down vector defines a situation in which the standoff is at a minimum, allowing for a good spine and rib correction. A drawback of the Holenka et al method is that the assumption of minimum standoff is not necessarily satisfied, so that the down position may in fact correspond to a significant standoff; without a standoff correction the results may be erroneous.

[009] In a centralized or stabilized tool, the standoff will generally be uniform with azimuth. Holenka (U.S. Pat. No. 5,513,528) and Edwards (U.S. Pat. No. 6,307,199) also show how azimuthal measurements of density may be diagnostic of bed boundaries intersected by an inclined borehole. In the absence of standoff corrections, this can only be a qualitative measurement.

[0010] U.S. Patent No. 6,584,837 to Kurkoski, fully incorporated by reference herein, discloses a LWD density sensor that includes a gamma ray source and at least two NaI detectors spaced apart from the source for determining measurements indicative of the formation density. A magnetometer on the drill collar measures the relative azimuth of the NaI detectors. An acoustic caliper is used for making standoff measurements of the NaI detectors. Measurements made by the detectors are partitioned into spatial bins defined by standoff and azimuth. Within each azimuthal sector, the density measurements are compensated for standoff to provide a single density measurement for the sector. The azimuthal sectors are combined in such a way as to provide a compensated azimuthal geosteering density. The method of the invention may also be used with neutron porosity logging devices.

[0011] MWD instruments, in some cases, include a provision for sending at least some of the subsurface images and measurements acquired to recording equipment at the earth's surface at the time the measurements are made using a telemetry system (i.e. MWD telemetry). One such telemetry system modulates the pressure of a drilling fluid pumped through the drilling assembly to drill the wellbore. The fluid pressure modulation telemetry systems known in the art, however, are limited to transmitting data at a rate of at most only a few bits per second. Because the volume of data measured by the typical image-generating well logging instrument is relatively large, at present, borehole images are generally available only using electrical cable-conveyed instruments, or after an MWD instrument is removed from the wellbore and the contents of an internal storage device, or memory, are retrieved.

[0012] Many types of well logging instruments have been adapted to make measurements which can be converted into a visual representation or "image" of the wall of a wellbore drilled through earth formations. Typical instruments for developing images of parameters of interest measurements include density measuring devices, electrical resistivity measuring devices and acoustic reflectance/travel time measuring devices. These instruments measure a property of the earth formations proximate to the wall of the wellbore, or a related property, with respect to azimuthal direction, about a substantial portion of the circumference of the wellbore. The values of the property measured are correlated to both their depth position in the wellbore and to their azimuthal position with respect to some selected reference, such as geographic north or the gravitationally uppermost side of the wellbore. A visual representation is then developed by presenting the values, with respect to their depths and azimuthal orientations, for instance, using a color or gray tone which corresponds to the value of the measured property.

[0013] One method known in the art for transmitting image-generating measurements in pressure modulation telemetry is described, for example, in U.S. Pat. No. 5,519,668 issued to Montaron. This method includes making resistivity measurements at preselected azimuthal orientations, and transmitting the acquired resistivity values to the surface through the pressure modulation telemetry. The method described in the Montaron '668 patent requires synchronization of the resistivity measurements to known rotary orientations of the MWD instrument to be able to decode the image data at the surface without transmitting the corresponding rotary orientations at which the measurements were made.

[0014] U.S. Patent No. 6,405,136 to Li, et al fully incorporated by reference herein, discloses a method for compressing a frame of data representing parameter values, a time at which each parameter value was recorded, and an orientation of a sensor at the time each parameter value was recorded. Generally the method includes performing a two-dimensional transform on the data in the orientation domain and in a domain related to the recording time. In one embodiment, the method includes calculating a logarithm of each parameter value. In one embodiment, the 2-D transform includes generating a Fourier transform of the logarithm of the parameter values in the azimuthal domain, generating a discrete cosine transform of the transform coefficients in the time domain. This embodiment includes quantizing the coefficients of the Fourier transform and the discrete cosine transform. One embodiment of the method is adapted to transmit resistivity measurements made by an LWD instrument in pressure modulation telemetry so that while-drilling images of a wellbore can be generated. The one embodiment includes encoding the quantized coefficients, error encoding the encoded coefficients, and applying the error encoded coefficients to the pressure modulation telemetry.

[0015] Other data compression techniques, for various applications, are described in several other U.S. patents, for example, U.S. Pat. No. 5,757,852 to Jericevic et al; U.S. Pat. No. 5,684,693 to Li; U.S. Pat. No. 5,191,548 to Balkanski et al; U.S. Pat. No. 5,301,205 to Tsutsui et al; U.S. Pat. No. 5,388,209 to Akagiri; U.S. Pat. No. 5,453,844 to George et al; U.S. Pat. No. 5,610,657 to Zhang; and U.S. Pat. No.

6,049,632 to Cockshott et al. Many prior art data compression techniques are not easily or efficiently applicable to the extremely low bandwidth and very high noise level of the communication methods of the typical MWD pressure modulation telemetry system, and, have not been suitable for image transmission by such telemetry.

[0016] U.S. Application 10/167,332 (Publication 20020195276 A1) to Dubinsky et al, entitled "Use of Axial Accelerometer for Estimation of Instantaneous ROP Downhole for Lwd and Wireline Applications" the contents of which are incorporated herein by reference, disclose that determination of the rate of penetration (ROP) of drilling has usually been based upon surface measurements and may not be an accurate representation of the actual ROP. This can cause problems in Logging While Drilling (LWD). . Because of the lack of a high-speed surface-to-downhole communication while drilling, a conventional method of measuring ROP at the surface does not provide a solution to this problem. However, the instantaneous ROP can be derived downhole with a certain degree of accuracy by utilizing an accelerometer placed in (or near) the tool to measure acceleration in the axial direction. When three-component accelerometers are used, the method may be used to determine the true vertical depth of the borehole.

[0017] There is a need for a method of determining subsurface features in downhole logging data, for example with azimuthal density variations from measurements made by a MWD logging tool. Such a method preferably provides for real-time determination of down hole parameter for communication to the surface, or provides for real time imaging of the subsurface environment during drilling operations. The present invention satisfies this need. It is desirable to have a system which enables transmission of data for imaging a wellbore through pressure modulation or other telemetry so that images of a wellbore can be developed during the drilling of a wellbore, wherein the rotary orientation of each image-developing measurement is included in the transmitted data. It is also desirable to efficiently and timely determine estimates of positions and orientations of boundaries between layers of earth formations.

SUMMARY OF THE INVENTION

[0018] The present invention provides a method and apparatus for logging an earth formation and acquiring subsurface information wherein a logging tool is conveyed in a borehole to obtain parameters of interest. The parameters of interest obtained may be density, acoustic, magnetic or electrical values as known in the art. As necessary, an azimuth associated with the parameters of interest measurements are obtained and corrections applied. The corrected data may be filtered and/or smoothed. The parameters of interest associated with azimuthal sectors are formed into a plurality of Cost Functions from which Regions of Interest are determined to resolve characteristics of the Features of interest within the Regions of Interest. Also, for initial delineation of Regions of Interest and associated Features, Cost Functions from a plurality of sectors may be combined to efficiently obtain prospective areas of the Cost Functions. Characteristics of these Features may be determined to obtain time or depth positions of bed boundaries and the Dip Angle of the borehole relative to subsurface structures, as well as the orientation of the logging equipment (borehole) and subsurface structure. Characteristics of the Features include time, depth, lithologies, structural depths, dip and thicknesses. The Regions of Interest may be generally characterized according to the behavior of the Regions in the neighborhood of various subsurface features. For example, a thin-bed type response may be characterized where the Region of Interest spans two local maxima with a local minimum between the maxima. There are at least four types of features (i.e. features of interest) that may be identified and/or extracted from Regions of Interest.

BRIEF DESCRIPTION OF THE FIGURES

[0019] The patent or application file contain at least one drawing executed in color. Copies of this patent or patent application publication with color drawing(s) will be provided by the Office upon request and payment of the necessary fee. The present invention and its advantages will be better understood by referring to the following detailed description and the attached drawings in which:

Figure 1 (PRIOR ART) shows an example of how density measurements made from a long spaced and a short spaced tool are combined to give a corrected density;

Figure 2 (PRIOR ART) shows an idealized situation in which a rotating tool in a wellbore has a minimum standoff when the tool is at the bottom of the wellbore;

Figure 3 shows a schematic diagram of a drilling system having a drill string that includes an apparatus according to the present invention;

Figure 4 illustrates a flow chart of the present invention;

Figure 5A illustrates raw density data with a Region of Interest;

Figure 5B illustrates a cost function display of obtained data with a Region of Interest and a Feature in the Region of Interest;

Figure 5C illustrates types of Features that may be associated with a Region of Interest;

Figure 6A illustrates a function that represents the Dip Angle relative to the well bore;

Figure 6B illustrates the relationship of Regions of Interest with Features and Dip Angle among the several azimuthal sectors, and shows both raw and smoothed (filtered) data;

Figure 7 illustrates an estimate of data size sample versus DC value for the Discrete Cosine Transform;

Figure 8 illustrates a data scanning method according to the Embedded Zerotree Wavelet Encoder;

Figure 9 illustrates raw density data across 8 sectors;

Figure 10 illustrates an uncompressed image reconstructed using the present invention with a compression of 300:1;

Figure 11 illustrates an uncompressed image reconstructed using the present invention with a compression of 150:1;

Figure 12 illustrates an uncompressed image reconstructed using the present invention with a compression of 100:1;

Figure 13 illustrates the acc error versus the compression ratio;

Figure 14 illustrates the Root-mean-square (RMS) error versus the compression ratio;

Figure 15 is a flow chart of an embodiment of the present invention;

Figure 16 is a flow chart of an embodiment of the present invention; and

Figure 17 is a flow chart of an embodiment of the present invention.

[0020] While the invention will be described in connection with its preferred embodiments, it will be understood that the invention is not limited thereto. It is intended to cover all alternatives, modifications, and equivalents which may be included within the spirit and scope of the invention, as defined by the appended claims.

DETAILED DESCRIPTION OF THE INVENTION

[0021] **Figure 3** shows a schematic diagram of a drilling system **110** having a downhole assembly containing an acoustic sensor system and the surface devices according to one embodiment of present invention. As shown, the system **110** includes a conventional derrick **111** erected on a derrick floor **112** which supports a rotary table **114** that is rotated by a prime mover (not shown) at a desired rotational speed. A drill string **120** that includes a drill pipe section **122** extends downward from the rotary table **114** into a borehole **126.** A drill bit **150** attached to the drill string downhole end disintegrates the geological formations when it is rotated. The drill string **120** is coupled to a drawworks **130** via a kelly joint **121**, swivel **118** and line **129** through a system of pulleys **127.** During the drilling operations, the drawworks **130** is operated to control the weight on bit and the rate of penetration of the drill string **120** into the borehole **126.** The operation of the drawworks is well known in the art and is thus not described in detail herein.

[0022] During drilling operations a suitable drilling fluid (commonly referred to in the art as "mud") **131** from a mud pit **132** is circulated under pressure through the drill string **120** by a mud pump **134**. The drilling fluid **131** passes from the mud pump **134** into the drill string **120** via a desurger **136**, fluid line **138** and the kelly joint **121.** The drilling fluid is discharged at the borehole bottom **151** through an opening in the drill bit **150.** The drilling fluid circulates uphole through the annular space **127** between the drill string **120** and the borehole **126** and is discharged into the mud pit **132** via a return line **135.** Preferably, a variety of sensors (not shown) are appropriately deployed on the surface according to known methods in the art to provide information about various drilling-related parameters, such as fluid flow rate, weight on bit, hook load, etc.

[0023] A surface control unit **140** receives signals from the downhole sensors and devices via a sensor **143** placed in the fluid line **138** and processes such signals according to programmed instructions provided to the surface control unit. The surface control unit displays desired drilling parameters and other information on a display/monitor **142** which information is utilized by an operator to control the drilling operations. The surface control unit **140** contains a computer, memory for storing data, data recorder and other peripherals. The surface control unit **140** also includes models and processes data according to programmed instructions and responds to user commands entered through a suitable means, such as a keyboard. The control unit **140** is preferably adapted to activate alarms **144** when certain unsafe or undesirable operating conditions occur.

[0024] A drill motor or mud motor **155** coupled to the drill bit **150** via a drive shaft (not shown) disposed in a bearing assembly **157** rotates the drill bit **150** when the drilling fluid **131** is passed through the mud motor **155** under pressure. The bearing assembly **157** supports the radial and axial forces of the drill bit, the downthrust of the drill motor and the reactive upward loading from the applied weight on bit. A stabilizer **158** coupled to the bearing assembly **157** acts as a centralizer for the lowermost portion of the mud motor assembly.

[0025] In the preferred embodiment of the system of present invention, the downhole subassembly **159** (also referred to as the bottomhole assembly or "BHA") which contains the various sensors and MWD devices to provide information about the formation and downhole drilling parameters and the mud motor, is coupled between the drill bit **150** and the drill pipe **122.** The downhole assembly **159** preferably is modular in construction, in that the various devices are interconnected sections so that the individual sections may be replaced when desired.

[0026] Still referring back to **Figure 3**, the BHA also preferably contains sensors and devices in addition to the above-described sensors. Such devices include a device for measuring the formation resistivity near and/or in front of the drill bit, a gamma ray device for measuring the formation gamma ray intensity and devices for determining the inclination and azimuth of the drill string. The formation resistivity measuring device **164** is preferably coupled above the lower kick-off subassembly **162** that provides signals, from which resistivity of the formation near or in front of the drill bit **150** is determined. A dual propagation resistivity device ("DPR") having one or more pairs of transmitting antennae **166a** and **166b** spaced from one or more pairs of receiving antennae **168a** and **168b** is used. Magnetic dipoles are employed which operate in the medium frequency and lower high frequency spectrum. In operation, the transmitted electromagnetic waves are perturbed as they propagate through the formation surrounding the resistivity device **164.** The receiving antennae

168a and **168b** detect the perturbed waves. Formation resistivity is derived from the phase and amplitude of the detected signals. The detected signals are processed by a downhole circuit that is preferably placed in a housing **170** above the mud motor **155** and transmitted to the surface control unit **140** using a suitable telemetry system **172.** In addition to or instead of the propagation resistivity device, a suitable induction logging device may be used to measure formation resistivity.

[0027] The inclinometer **174** and gamma ray device **176** are suitably placed along the resistivity measuring device **164** for respectively determining the inclination of the portion of the drill string near the drill bit **150** and the formation gamma ray intensity. Any suitable inclinometer and gamma ray device, however, may be utilized for the purposes of this invention. In addition, an azimuth device (not shown), such as a magnetometer or a gyroscopic device, may be utilized to determine the drill string azimuth. Such devices are known in the art and are, thus, not described in detail herein. In the above-described configuration, the mud motor **155** transfers power to the drill bit **150** via one or more hollow shafts that run through the resistivity measuring device **164.** The hollow shaft enables the drilling fluid to pass from the mud motor **155** to the drill bit **150.** In an alternate embodiment of the drill string **120,** the mud motor **155** may be coupled below resistivity measuring device **164** or at any other suitable place.

[0028] The drill string contains a modular sensor assembly, a motor assembly and kick-off subs. In a preferred embodiment, the sensor assembly includes a resistivity device, gamma ray device and inclinometer, all of which are in a common housing between the drill bit and the mud motor. The downhole assembly of the present invention preferably includes a MWD section **168** which contains a nuclear formation porosity measuring device, a nuclear density device, an acoustic sensor system placed, and a formation testing system above the mud motor **164** in the housing **178** for providing information useful for evaluating and testing subsurface formations along borehole **126.** A downhole processor may be used for processing the data.

[0029] Wireline logging tools have been used successfully to produce subsurface images. For MWD applications, density tool measurements and other measurements have been stored in the MWD tool's memory. Therefore subsurface images and parameter determinations haven't been generally available for real time applications such as geosteering.

[0030] The present invention which provides for acquiring parameters of interest is discussed with reference to a density measurement tool that emits nuclear energy, and more particularly gamma rays, but the method of the present invention is applicable to other types of logging instruments as well (e.g., acoustic methods, magnetic resonance and electrical methods). Wireline gamma ray density probes are well known and comprise devices incorporating a gamma ray source and a gamma ray detector, shielded from each other to prevent counting of radiation emitted directly from the source. During operation of the probe, gamma rays (or photons) emitted from the source enter the formation to be studied, and interact with the atomic electrons of the material of the formation by photoelectric absorption, by Compton scattering, or by pair production. In photoelectric absorption and pair production phenomena, the particular photons involved in the interacting are removed from the gamma ray beam. Instruments for making measurements of acoustic properties and gamma-gamma density have several advantages known in the art, and it should be understood that the instruments disclosed are not the only instruments that can be used to make such measurements. Accordingly, the invention is not to be limited to measurements of parameters of interest made by the particular instruments described herein.

[0031] The present invention provides for subsurface feature extraction, data compression, dip angle calculation, and semi-real-time data transmission to the surface. Transmission of raw or reduced subsurface data in near real-time to the surface provides for calculation of subsurface structure dip angles in semi or near real time for geosteering. The invention may be implemented in firmware and/or software downhole. For example, the invention provides for receiving the acquired subsurface data divided into sectors (eight, for example), the data are compressed, the apparent dip may be calculated, the data and/or the calculations may be transmitted to the surface and uncompressed for display. For example a formation bed boundary may display as a sine wave. An example product is a downhole apparatus with a processor with software that receives density data which may be divided into sectors (for example in eight sectors), compresses the data, calculates the apparent dip angle, formats the data for transmission, uncompresses the data at the surface and formats the data for further uses.

[0032] The compression algorithm and apparent dip angle calculation are based on feature extraction concepts. The present invention provides an implementation in three modules: i) compression, ii) reconstruction and iii) display.

[0033] The compression module receives data (which may be formatted in blocks) of the density for the standoff sectors, for example eight sectors, along with an optional set of parameters which may be selected from predefined parameters to customize the compression according to user need and a priori knowledge of the downhole environment. This module runs downhole to compress the image, code the image, calculate the parameters of the dip angle, code the parameters of the dip angle, format the data and transmit the data to the telemetry.

[0034] **Figure 4** illustrates a block diagram. Raw data **401** along with selected parameters **403** goes into the Preprocessing Module **405**. The Preprocessing Module **405** ensures that data values are in expected ranges, for example density is in the range from 1.5 gm/cc to 3gm/cc. In the case where the density data has a value outside this range, the preprocessing module either interpolates the data or generates a segmentation based on the number of invalid or null data points. The preprocessing module receives both the data and the compression parameters from the memory module, which may be flash memory. The parameters may be preset or supplied by downlink.

[0035] The preprocessing module **405** performs three separate tasks. The first task is to get the parameters of the algorithm. Based on the downlink or preset parameters, the parameters are set in memory. The algorithm then passes the parameters to the data collection procedure. A flash memory module is one way that parameters and instructions may be stored and provided for the present invention.

[0036] The second task is data collection. Based on the parameters for the compression, pointers are going to be generated to point to the start of each data block that needs to be processed and the block lengths.

[0037] Third task is to check the density data values. In some cases density data values appear in the memory as a null value for many reasons. The preprocessing module **405** applies the following strategy on the null value: If the number of reading that contains a null value is less than or equal to a selected value, an interpolation is made. If the number of the null data that contains a null value is more than the selected value, the image is divided into two parts, which is called segmentation.

[0038] The Feature Extraction Module **407** runs if it has been chosen or enabled (for example in the flash memory parameters). The feature extraction module generates a cost function based on both the direction of the change and the change in the value of the parameter of interest (e.g., density data). Any maximum or minimum of that cost function, or variations of maxima and minima, indicates the possible locations of bed boundaries, i.e. the possibility of a feature. The region between the location of the two zeros around the maximum or the minimum that results from the first derivative of that cost function represents a region of interest i.e. the region that likely contains one or more features of interest. The block of data or number of samples within a cost function may be set arbitrarily. If the absolute value of the last value of the cost function is close to zero, it means that there are no features that share the current block of data and the next block of data. If the absolute value of the cost function value is close to or greater than one, it means that there are feature/features shared between/among the current block of data and the next block of data. The distance between the location of the last zero of the first derivative of the cost function and the end of the current data block determine an overlap region. The overlap region will be added to the next adjacent block of data. This guarantees that the next block of data will contain a complete feature.

[0039] **Figure 5A** illustrates raw data containing features of interest. **Figure 5B** illustrates the **Cost Function**, including the **Feature** location and a **Region of Interest**. This feature could be a “thin bed” or other subsurface structure or bedding boundary.

[0040] Extracting the **Feature** characteristics from within the **Cost Function** is accomplished by examination and comparison of the behavior of the excursions of the waveform (or data trace) in relation to a chosen reference or in relation to localized changes in the **Cost Function**. As illustrated in **Figure 5B,** the **Cost Function** is analyzed to discover parameters that satisfy all chosen constraints, and produce an optimum value for determining features of interest in the **Cost Function**. The **Cost Function** examination optimally works out how to adjust the design variables for subsequent runs. This produces an optimized design for efficient **Feature** identification and extraction. In the example shown here, the **Region of Interest** spans a waveform section of parameter values that is the area between and including two local maxima. These local maxima bracket a local minimum, which minimum coincides with the position of a **Feature**. Suitable wavelet functions may be chosen to deconvolve the Feature efficiently to delineate these maxima and minima in order obtain feature positions in terms of time, depth, dip angle or other characteristics.

[0041] While **Figure 5B** illustrates a **Region of Interest** spanning local minima, there are three other features of interest that may be found in and around a Region of Interest, which Features are illustrated in **Figure 5C** relative to an arbitrary reference **509** demarking relative positive from relative negative values for purposes of illustration. Parameters of interest such as density may all be obtained as positive values, so it is the local variations that vary around an arbitrary reference. In addition to the local minima **501**, other Feature types include local maxima **503**, a transition from a local maximum to a local minimum **505**, and a transition from a local minimum to a local maximum **507**. A local maxima feature **503** could represent a low density thin bed; a local minimum **501** can represent a high density thin bed. Whether a bed is termed 'thin' or not, of course, is relative to both bed size and/or sample interval. An example of transition from local maximum to local minimum **505** is a step decrease in a density reading. An example of transition from local minimum to local maximum **507** is a step increase in a density reading. There are many choices for wavelets that may be used to efficiently identify Features within Regions of Interest.

[0042] Calculation of the Apparent Dip Angle: Dip Angle calculation is illustrated at **419** in **Figure 4**. Because a plane intersects a well bore as a periodic function, fitting a suitable mathematical function, for example a transcendental or a wavelet function, to the **Feature** position data as illustrated in **Figure 6A** is straightforward (e.g., a Discrete Cosine Transform). **Figure 6A** illustrates a function that represents the Dip Angle **601** relative to the well bore across several sectors. The dip angle function **601** along the sections of the well bore conforms to the **Feature** positions that have been determined from the analysis of the **Cost Function**. The **Cost Function** as illustrated in **Figure 6B** across multiple azimuthal sectors indicates the location of the **Region of Interest** where a **Feature** exists along the **Dip Angle 601**. If the cost function has a minimum value it means that the density data has been decreasing and we will look for a local minimum value in the **Region of Interest**. If the cost function has a maximum value it means that the density data has been increased and we will look for a maximum within the **Region of Interest** (for example a **Feature** such as **501** in **Figure 5B** and **5C**).

[0043] **Figure 6B** illustrates a smoothed version of the data with the region of interest generated for each sector. The direction of change of the total density data may be examined in the eight sectors in both the **Raw Data** and the same eight sectors of the **Smooth Data** smoothed version for the raw data with the region of interest. For a decision to be made in preprocessing (e.g. **Figure 4** preprocessing **405**) that there is a feature of interest in a specific location, the following parameters are a non-exclusive group that may be used: 1) The time location where the minimum or maximum value of the feature is located, 2) The peak to peak amplitude of the feature (and how many samples), 3) the direction of the apparent dip angle with respect to the tool (or borehole).

[0044] **Figure 6B** shows the calculation of the apparent dip angle. The dip may be determined by fitting a function, for example the function represented by the line **601**, superimposed on the **Features** of the data with adjacent sectors **Region of Interest**. The image trace of desired imaging features of interest such as bedding boundaries or other subsurface structure boundaries will most often cross boreholes with a sinusoidal behavior. Bedding boundaries will display as a sinusoid. This sinusoidal behavior of the Features (i.e., **601**) allows a data compression related algorithm such as the 2-D Discrete Cosine Transform (DCT) to operate with good results, and for the apparent dip angle to fall out of the compression process when energy of the transform terms is minimized.

[0045] Transformation is illustrated at **409** in **Figure 4**. The 2-D Discrete Cosine Transform (DCT) has been used as a method of energy localization. The 1-D DCT for a vector of length N is given by equation (1), for the range m to N-1. The DCT will be calculated in the sector direction then in the time or depth dimension.

$$\begin{cases} y(m) = \sqrt{\dfrac{2}{N}} \displaystyle\sum_{k=0}^{N-1} x(k) \cos \dfrac{(2k+1)m\pi}{2N} & m = 0 \\ y(m) = \sqrt{\dfrac{2}{N}} \displaystyle\sum_{k=0}^{N-1} x(k) \cos \dfrac{(2k+1)m\pi}{2N} & m \neq 0 \end{cases} \qquad (1)$$

[0046] Since the density data range from 1.5 g/cc to 3.00 g/cc (within a fairly narrow range), the Discrete Cosine (DC) value may be replaced by the difference between the DC value and its estimate. The estimate value of the DC is based on the size of the data. **Figure 7** illustrates the estimate DC value of the 2-D DCT. The x-axis shows the size of the data. The y-axis shows the estimate DC value of the 2-D DCT.

[0047] The output matrix of DCT coefficients contains integers. The signal energy lies at relatively low frequencies; these appear in the upper left corner of the DCT (Table 1). The lower right values represent higher frequencies, and are often small enough to be neglected with little visible distortion. **Table 1** shows how the DCT operates on the 8 by 8 matrix.

92	3	-9	-7	3	-1	0	2
-39	-85	12	17	-2	2	4	2
-84	62	1	-18	3	4	-5	5
-52	-36	-10	14	-10	4	-2	0
-86	-40	-49	-7	17	-6	-2	6
-62	65	-12	-2	3	-8	-2	0
-17	14	-36	17	-11	3	3	-1
-54	32	-9	-9	22	0	1	3

Table 1 (was Table 2): DCT Coefficients

[0048] Quantization is illustrated at **411** in **Figure 4**. There is a tradeoff between image quality and the degree of quantization. A large quantization step size can produce unacceptably large image distortion. This effect is similar to quantizing Fourier series coefficients too coarsely; large distortions would result. Unfortunately, finer quantization leads to lower compression ratios. The question is how to quantize the DCT coefficients most efficiently. Because of human eyesight's natural high frequency roll-off, these frequencies play a less important role than low frequencies. This lets JPEG use a much higher step size for the high frequency coefficients, with little noticeable image deterioration.

[0049] The quantization matrix is the 8 by 8 matrix of step sizes (sometimes called quantum) – one element for each DCT coefficient. It is usually symmetric. Step sizes will be small in the upper left (low frequencies), and large in the upper right (high frequencies); a step size of 1 is the most precise. The quantizer divides the DCT coefficient by its corresponding quantum and then rounds to the nearest integer. Large quantization matrix coefficients drive small coefficients down to zero. The result: many high frequency coefficients become zero, and therefore easier to code. The low frequency coefficients undergo only minor adjustment. By choosing parameterization of the matrices efficiently, zeros among the high frequency coefficients leads to efficient compression. **Table 2** shows the quantization matrix.

3	4	5	6	7	8	9	10
4	5	6	7	8	9	10	11
5	6	7	8	9	10	11	12
6	7	8	9	10	11	12	13
7	8	9	10	11	12	13	14
8	9	10	11	12	13	14	15
9	10	11	12	13	14	15	16
10	11	12	13	14	15	16	17

Table 2: The Quantization Matrix

30	0	-1	0	0	0	0	0
-7	-8	1	1	0	0	0	0
-12	6	0	-1	0	0	0	0

-5	-3	0	0	0	0	0	0
-7	-3	3	0	0	0	0	0
-4	4	0	0	0	0	0	0
-1	0	-1	0	0	0	0	0
-3	1	0	0	0	0	0	0

Table 4: The quantized Data

[0050] **Table 3** shows the quantized data of given in **Table 1**. Quantization has been done into two steps: 1) Dynamic range reduction. 2) EZW (Embedded Zerotree Wavelet Encoder). A linear quantizer has been used. However, in some cases some of the coefficients have a very big value relative to other coefficient values. Most probably those values will be located in the first column of data based on the property of the 2-D DCT. The number of the elements in the first column depends on the data size, however for a data size of length less than 360, it appears that if there is a big coefficient they have a big chance to appear in the first eight element of the first column. So the integer value of the first few coefficients will be coded separately and they will be replaced by the difference between the actual value and the coded value. The rest of the data will be multiplied by 100 and converted into integers, and then it will be quantized according to the EZW method. **Figure 8** shows how the EZW method scans the image. See *Embedded Image Coding Using Zerotrees of Wavelet Coefficients*, Shapiro, J.M., IEEE Transactions on Signal Processing, Vol. 41. No 12, December 1993, or N.M. Rajpoot and R.G. Wilson, *Progressive Image Coding using Augmented Zerotrees of Wavelet Coefficients*, Research Report CS-RR-350, Department of Computer Science, University of Warwick (UK), September 1998.

[0051] The image will be scanned in multiple passes. In every pass the elements will be compared to a threshold. If the element values exceed the threshold (e.g. the threshold could equal 20, but this will be data and/or area dependent) it will be replaced by the actual value of the elements minus 1.5 times the threshold. Then the threshold will be reduced in a predetermined order and more passes will be done until the maximum allowable size of the data will be achieved.

[0052] The quantized data may be coded into different formats at **423** in **Figure 4** depending on whether an image or only selected parameters (e.g. Dip Angle, Feature depth, and other associated characteristics) are to be transmitted to the surface. The first format is for dip angle transmission (e.g., from **419** to **421** in **Figure 4**); the second format is for image transmission (as illustrated from **411** to **421** in **Figure 4**). An example for Dip Angle parameters may be coded as follows: The buffer size will be set to 6 bytes. The first bit as zero indicates the that the packet has dip angle data, the next 17 bits indicate the time where the minimum of the feature has occur, the next 8 bits indicate the amplitude of the feature, and the next three bits indicate the sector where the maximum has occurred. After data are coded and formatted, the data may be further formatted and compressing and encoded such that the encoded, compressed values are applied (**425 Figure 3**) to a selected position in a telemetry format for transmission (**413 Figure 4**) to the surface recording unit.

[0053] If the data are for an image, the first bit of the code will be '1' indicating that the image has data followed by 17 bits for the time of the first data, followed by some overhead, then the data. The data will be coded into parts: 1) The Dynamic range reduction Code; 2) The EZW Code. The Dynamic Range Reduction Code: the first eight data points assigning three bits for every point. If the data point has a maximum value it indicates that the next value should be added to the current value to the actual data value. The output of the EZW is one of the four symbols (P, N, Z, and T). Where is the symbol T has more probability to be found in the data, T is going to be assigned to 0, Z is going to be assigned 10, N is going to be assigned 110, and P is going to be assigned 111.

[0054] The EZW (Embedded Zerotree Wavelet Encoder) may be inefficient when it is used with DCT coefficients. However, by rearranging the DCT blocks in specific order, it is possible to use EZW with DCT in a very efficient way, and thereby further, to transmit data in multiple resolutions so that a plurality of resolutions of the data may be transmitted and recombined according to the ultimate resolution desired. The Discrete Cosine Transform may be used for multi-resolution image compression to compress and decompose the Image with low computations compared to wavelets. It allows for the transmission of one or more resolution levels of the compressed image in a noise channel, and possibly losing only a resolution level or partial resolution level due to noise instead of losing the entire image. Also the images and/or compressed images can be stored in the memory (e.g., in flash memory) downhole in high resolution format, so the user can transmit only the resolution or plurality of resolutions needed or desired per image based on the setting for the algorithm parameters.

[0055] Matrix Rearrangement: the input image will be dividing into N by N blocks, and the DCT will be used on every block. The DC coefficient of every block will be replaced by the difference between the DC coefficient and its estimate value. The new DCT matrixes will be rearrange into new matrix suitable for LZW. **Table 5** and **Table 6** show two blocks of DCT matrix. The two block of the DCT will be arranged into a new matrix as following.

40	2	-1	-3	0	0	0	0
20	-8	1	1	0	0	0	0
-12	5	2	-1	0	0	0	0
-2	11	5	0	0	0	0	0
10	14	0	0	0	0	0	0
-3	4	1	0	0	0	0	0
14	2	0	1	0	0	0	0
6	3	1	0	0	0	0	0

Table 5: The DCT of two blocks

[0056] The first column of the DCT block will become the first row on the new if the dimensions of the new matrix allows, if not it will start from the next row of the new matrix. The second columns of the DCT blocks of the new matrix as above until the all the DCT blocks has been scanned. The new matrix may not be symmetric but the LSW can work in non symmetric matrix and still give compression ration higher than the JPEG. Symmetric matrix gives much higher compression ratio. **Table 6** shows the new matrix after rotation for two DCT blocks.

[0057] The image will be scanned in multiple passes in every pass the every element will be indicated if it is above a threshold, the threshold if it is above the threshold it will be replaced by the actual value of the elements minus 1.5 times the threshold. The threshold will be reduced in predetermined order and more pass will be done until the maximum allowable size of the data will be achieved.

-15	-7	-12	-5	-7	-4	-1	-3
5	20	-12	-2	10	-3	14	6
0	-8	6	-3	-3	4	0	1
2	-8	5	11	14	4	2	3
-1	1	0	0	3	0	-1	0
-1	1	2	5	0	1	0	1
0	1	-1	0	0	0	0	0
-3	1	-1	0	0	0	1	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0

Table 6: The DCT of the new matrix after rearrangement of the DCT blocks

[0058] Reconstruction Module: The second module runs at the surface. The module receives block/blocks of binary number that are transmitted and a copy of the selected parameters. The second module may be implemented, for example, as an executable file using Matlab.

[0059] The output of the second module may be an ASCII file that represents the image at time bases. The second module encodes the received block/blocks of data and determines if the data represents an image or represents the parameters of the apparent dip angle. If the received blocked is an image, the second module generates an ASCII file. The first row of the ASCII file represents the time of every reading in the next eight columns. The first column has the time (hh:mm:ss), and the second column to the ninth column has the density data that represent the image.

[0060] Data Reconstruction: The executable file at the surface receives the data packet and the parameter which has been down linked. If the first bit is zero it generates the Apparent Dip angle parameters. If the first bit of the data is one it extracts the image. **Figure 9** shows raw data which has been compressed with three levels of compression using a multi-resolution compression algorithm like the Discrete Cosine Transform. **Figure 10** shows the data at one resolution that has been compressed with a relatively high compression ratio (with a compression of 300:1). **Figure 11** shows the data has been compressed with a medium compression ratio (with a compression of 150:1). **Figure 12** shows the data has been compressed with a relatively low compression ratio (a compression of 100:1 or three times as much data as for **Figure 10**).

[0061] Display Module: The image represents structure of the earth so it may be more convenient to color map the image with "earth tone" colors. Because of human eyesight's natural high frequency roll-off, these frequencies play a less important role than low frequencies. The density data represent low resolution images, so it may be more convenient to smooth the image in the depth direction before displaying it. Also azimuthally sectored log data may be interpolated to generate a smooth image in both the depth direction and the azimuthally direction. A suitable linear interpolation and color map scheme may be implemented. Bed boundaries will display as sine waves.

[0062] Error Analysis: One of the most challenging problems in image compression is to measure the quality of image in terms of error. Even most of the common error analysis gives an indication to the amount of error in the image, it is necessary that an image with lower error measurement looks better than image with bigger error measurement.

[0063] Examples of two criteria that have been used to measure the error in the image as shown in equation 2 and equation 3.

$$acc\_Error = \sqrt{\frac{\sum_{i}^{N}\sum_{j}^{M}(RawData - \mathrm{Re}\,constructed)^2}{\sum_{i}^{N}\sum_{j}^{M}(RawData)^2}} \qquad (2)$$

$$rms\_Error = \frac{\sqrt{\sum_{i}^{N}\sum_{j}^{M}(RawData - \mathrm{Re}\,constructed)^2}}{NM} \qquad (3)$$

[0064] The error measurements do not measure the image quality very precisely. **Figure 13** shows the acc error versus the compression ratio and **Figure 14** shows the Root-mean-square (RMS) error versus the compression ratio. The user's needs change according to the drilling conditions. In order to configure the tool according to the user's needs the tool has to be configured either on the surface or on the fly by downlink.

[0065] On the surface: A parameter table may be updated on the surface. In cases where the parameter table has not been updated the system will use default or preset values.

[0066] Down Link: In order to configure the system on the fly, down link commands are required. In cases where the tool has not been configured at the surface, a new configuration may be sent by a down link command. The data may be immediately available for use. The available configurations options are as in the following examples:

[0067] The portion of density data that needs to be transmitted:

a. The last block from the current location of the buffer; the block size is 8*128
b. the last N blocks
c. The entire image
d. The region/regions where the last feature/features has/have been located
e. The parameters or characteristics of the Apparent Dip Angle

[0068] The level of compressed for the entire image

a. Low compression (e.g. 60:1)
b. Medium Compression (e.g. 90:1)
c. High Compression (e.g. 150:1)

[0069] The method of data transmission

a. On demand i.e. downlink

b. Periodic function generated by the master. The period function will be activated/deactivated on the surface and/or configure by a down link command. The period function commands are:
    i. Every power on transmit the last block of data
    ii. Every power on transmit the last region of interest
    iii. Every power on transmit the parameters of the apparent dip angle
    iv. Every power on transmit a combination from the above
    v. When the image is available (i.e. every 1280 sec)
    vi. When a region of interest is available i.e. check every 1280 sec
    vii. When the parameters of the apparent dip angle available i.e. every 320 sec.

[0070] As illustrated in **Figure 15** the invention provides method and apparatus for logging an earth formation and acquiring subsurface information wherein a logging tool is conveyed in borehole **1502** to obtain parameters of interest **1504**. The parameters of interest obtained may be density, acoustic, magnetic or electrical values as known in the art. As necessary, a standoff and azimuth associated with the measurements are obtained **1506** and corrections applied. The corrected data may be filtered and/or smoothed as necessary. The parameters of interest associated with azimuthal sectors are formed into a plurality of Cost Functions **1508** from which Regions of Interest are determined **1510** to resolve characteristics of the Features of interest within the Regions. Also, for initial delineation of Regions of Interest and associated Features, Cost Functions from a plurality of sectors may be combined to efficiently obtain prospective areas of the Cost Functions. The Features may be determined to obtain time or depth positions of bed boundaries and the Dip Angle **1512** of the borehole relative to subsurface structures, as well as the orientation of the logging equipment and subsurface structure. Characteristics of the Features include time, depth, dip of subsurface structure. The Regions of Interest may be generally characterized according to the behavior of the Regions in the neighborhood of various subsurface features. For example, a thin-bed type response may be characterized as shown in **Figure 5B** where the **Region of Interest** spans two positive amplitude local maxima with a local minimum between the maxima. This is further illustrated in

Figure 5C by Region of Interest **501**. **Figure 5C** illustrates four types of Regions of Interest that have Features that may be identified, and illustrates how the Features are disposed about an arbitrary reference **509**. The inverse of the **501** situation is illustrated by Region of Interest **503** where two minima bracket a maximum. Region of Interest **505** illustrates the situation where a Feature exists between in an area of maximum values which has a relatively fast transition to minimum values. Region of Interest **507** illustrates the situation where a Feature exists between in an area of minimum values which has a relatively fast transition to maximum values.

[0071] As illustrated in **Figure 16** the invention provides method and apparatus for logging an earth formation and obtaining a plurality of parameters of interest of an earth formation **1602** penetrated by a wellbore at azimuthally spaced apart positions in the wellbore and defining a plurality of azimuthal sectors associated with the parameters of interest. The parameters of interest obtained may be density, acoustic, magnetic or electrical values as known in the art. Pluralities of Cost Functions **1604** are determined from the plurality of parameters of interest associated with the azimuthal sectors. Features are determined within the plurality of Cost Functions **1606**. A Dip Angle is determined from the Features **1608** determined from the Cost Functions. The Dip Angle is then encoded **1610** and transmitted to the surface recording unit for further uses.

[0073] As illustrated in **Figure 17** the invention provides method and apparatus for logging an earth formation and acquiring subsurface information wherein a logging tool is conveyed in borehole **1702** to obtain parameters of interest **1704**. The parameters of interest obtained may be density, acoustic, magnetic or electrical values as known in the art. As necessary, a standoff and azimuth associated with the measurements are obtained **1706** and corrections applied. The corrected data may be filtered and/or smoothed as necessary. At this point, the parameters of interest associated with azimuthal sectors may be encoded at a plurality of resolutions using a Discrete Cosine Transform to obtain encoded data **1708** that may be transmitted to the surface **1710**. **Figures 10, 11** and **12** demonstrate the recombination of the plurality of resolutions as the compression changes from 300:1 in **Figure 10**, 150:1 in **Figure 11** and finally 100:1 as the third input of resolution is combined.

[0074] 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 and spirit of the appended claims be embraced by the foregoing disclosure.

What is claimed is:

1. A method of logging an earth formation comprising:
   (a) conveying a logging tool into a borehole in the earth formation and rotating the tool therein;
   (b) making a plurality of measurements of a parameter of interest of the earth formation during rotation of the tool;
   (c) determining an azimuth associated with each of said measurements;
   (d) determining at least one Cost Function related to said plurality of measurements; and
   (e) determining from said at least one Cost Function at least one Region of Interest.

2. The method of claim 1 further comprising determining a Dip Angle relative to said borehole by fitting a selected mathematical function to a subset of said plurality of measurements associated with said Region of interest.

3. The method of claim 2 wherein said selected mathematical function is a Discrete Cosine Transform.

4. The method of claim 1 wherein said Region of interest further comprises a Feature of interest, wherein said Feature of interest is selected from the group consisting of: i) a local minima, ii) a local maxima, iii) a transition from a local maximum to a local minimum, and iv) a transition from a local minimum to a local maximum.

5. The method of claim 1 wherein the parameter of interest is selected from the group consisting of: i) density, ii) porosity, iii) electrical resistivity, iv) a nuclear magnetic resonance property, and v) acoustic reflectance.

6. The method of claim 1 further comprising compressing the determined Region of interest using a Discrete Cosine Transform for multi-resolution image compression.

7. The method of claim 1 further comprising encoding said at least one Region of Interest to obtain encoded data and transmitting said encoded data to a surface recording unit.

8. The method of claim 1 further comprising:
   i) transforming said Region of Interest using a mathematical function to produce transform terms;
   ii) determining a geographic orientation of azimuthal sectors relative to the borehole;
   iii) adjusting the corresponding azimuthal orientations with respect to a trajectory of the borehole to provide an orientation of the transform terms with respect to a selected geographic reference; and
   iv) developing an image from the transform terms with respect to said selected geographic reference.

9. The method of claim 1 further comprising displaying the Region of Interest as a sine wave.

10. An apparatus for logging while drilling of a borehole in an earth formation comprising:
   (a) a drill collar carrying a drill bit for drilling the borehole;
   (b) a sensor carried by the drill collar for making measurements of a parameter of interest of the earth formation;
   (c) a processor for determining a Cost Function related to said measurements and for determining from said Cost Function at least one Region of Interest.

11. The apparatus of claim 10 wherein the sensor is selected from the group consisting of: i) a density sensor, ii) a porosity sensor, iii) an electrical resistivity sensor, iv) a nuclear magnetic resonance property sensor, and v) an acoustic reflectance sensor.

12. The apparatus of claim 10 further comprising telemetry to communicate data to a surface recording unit.

13. A method for obtaining subsurface information relative to a wellbore using a downhole logging tool, comprising:
    (a) obtaining a plurality of parameters of interest of an earth formation penetrated by a wellbore at azimuthally spaced apart positions in the wellbore;
    (b) determining at least one Cost Function comprising said plurality of parameters of interest;
    (c) determining a Feature within said at least one Cost Function; and
    (d) determining a Dip Angle from said Feature.

14. The method of Claim 13 further comprising encoding said Dip Angle and transmitting said Dip Angle to a surface recording unit.

15. The method of Claim 14 wherein said encoding further comprises compressing said Dip Angle using a transform for multi-resolution image compression.

16. The method of claim 13 wherein said Feature is selected from the group consisting of: i) a local minimum, ii) a local maximum, iii) a transition from a local maximum to a local minimum, and iv) a transition from a local minimum to a local maximum.

17. The method of claim 13 wherein the parameters of interest are selected from the group consisting of: i) density, ii) magnetometer, iii) electrical receptivity, iv) a nuclear magnetic resonance property, and v) acoustic energy.

18. The method of claim 14 wherein transmitting comprises measurement while drilling telemetry.

19. The method of claim 14 further comprising detecting the encoded Dip Angle at the surface recording unit from the telemetry.

20. The method of claim 14 further comprising displaying said Dip Angle as a sine wave.

21. The method of claim 13 wherein determination of said Dip Angle of earth formations further comprises:
    i) transforming said Feature using a selected mathematical function to produce transform terms;
    ii) determining a geographic orientation of azimuthal sectors relative to the wellbore;
    iii) adjusting the corresponding azimuthal orientations with respect to a trajectory of the wellbore to provide an orientation of the transform terms with respect to a selected geographic reference; and
    iv) determining the Dip Angle from the transform terms with respect to said selected geographic reference.

22. A method of logging an earth formation comprising:
    (a) conveying a logging tool into a borehole in the earth formation and rotating the tool therein;
    (b) making a plurality of measurements of a parameter of interest of the earth formation during rotation of the tool;
    (c) determining an azimuth associated with each of said measurements;
    (d) encoding said plurality of measurements of a parameter of interest at a plurality of resolutions using a transform to obtain encoded data; and
    (e) transmitting said encoded data to a surface recording unit.

23. The method of claim 22 further comprising determining a Cost Function related to said plurality of measurements; and determining from said Cost Function at least one region of interest comprising a Feature of interest.

24. The method of claim 23 wherein said Feature of interest is selected from the group consisting of: i) a local minima, ii) a local maxima, iii) a transition from a local maximum to a local minimum, and iv) a transition from a local minimum to a local maximum.

25. The method of claim 22 wherein the parameter of interest is selected from the group consisting of: i) density, ii) porosity, iii) electrical resistivity, iv) a nuclear magnetic resonance property, and v) acoustic reflectance.

26. The method of claim 23 further comprising compressing the determined Feature of interest using a Discrete Cosine Transform for multi-resolution image compression.

27. The method of claim 23 wherein an earth formation bedding boundary is determined from the parameter of interest and displayed at the surface recording unit as a sine wave.

28. The method of claim 22 wherein said transform is a Discrete Cosine Transform.

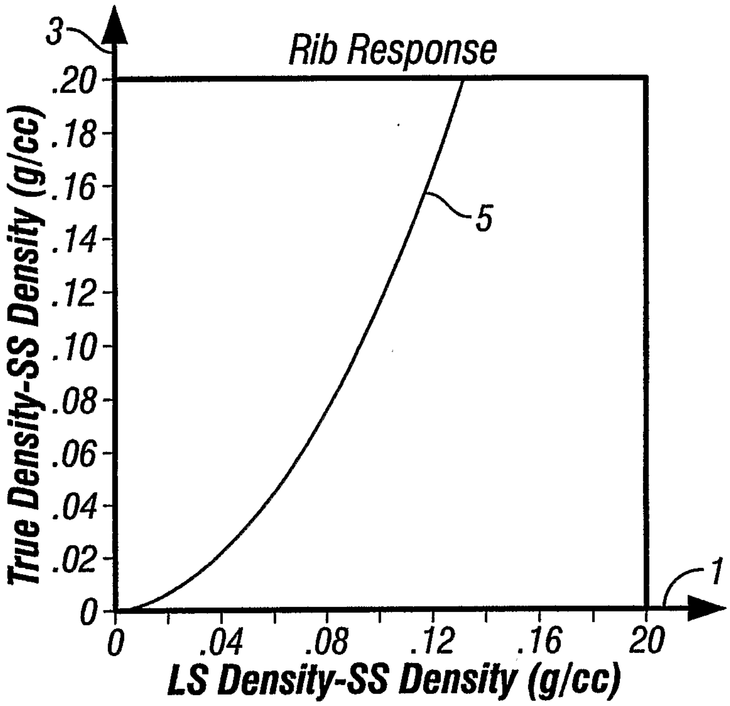


FIG. 1
(Prior Art)

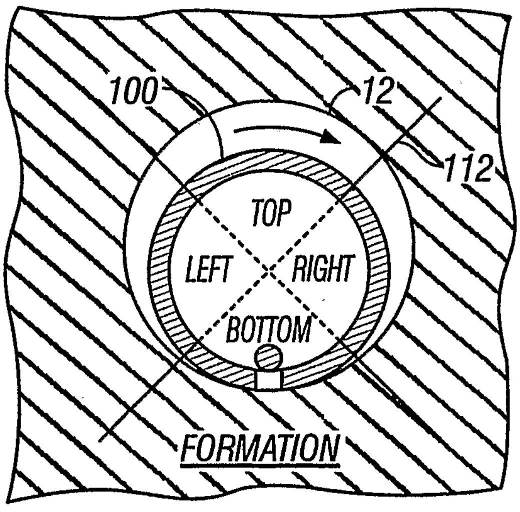


FIG. 2

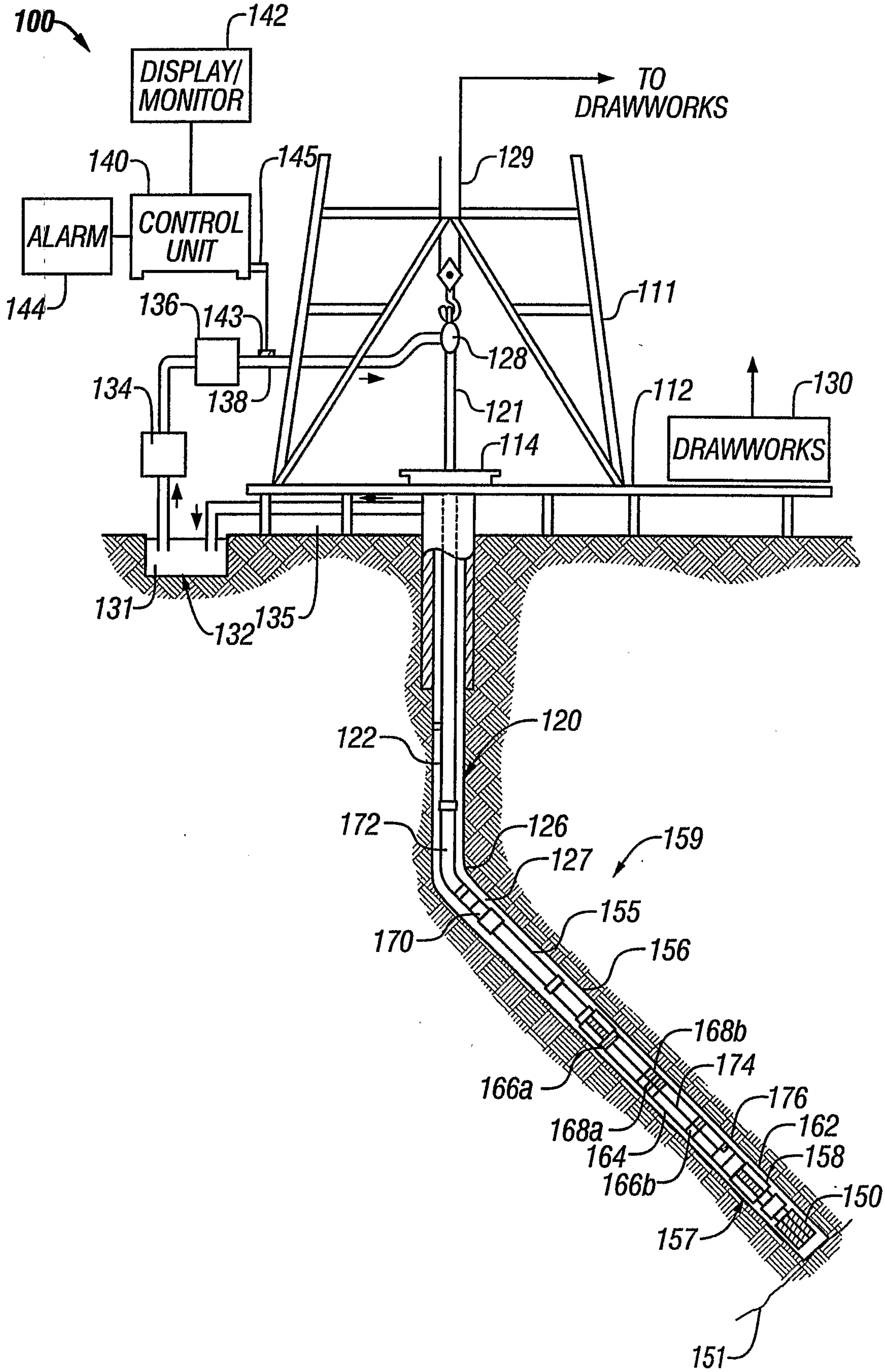

100
142
DISPLAY/ MONITOR
TO DRAWWORKS
140
145
129
ALARM
CONTROL UNIT
111
144
136
143
128
134
138
121
112
130
114
DRAWWORKS
131
132
135
122
120
172
126
159
127
170
155
156
168b
166a
174
176
168a
162
164
158
166b
150
157
151

FIG. 3

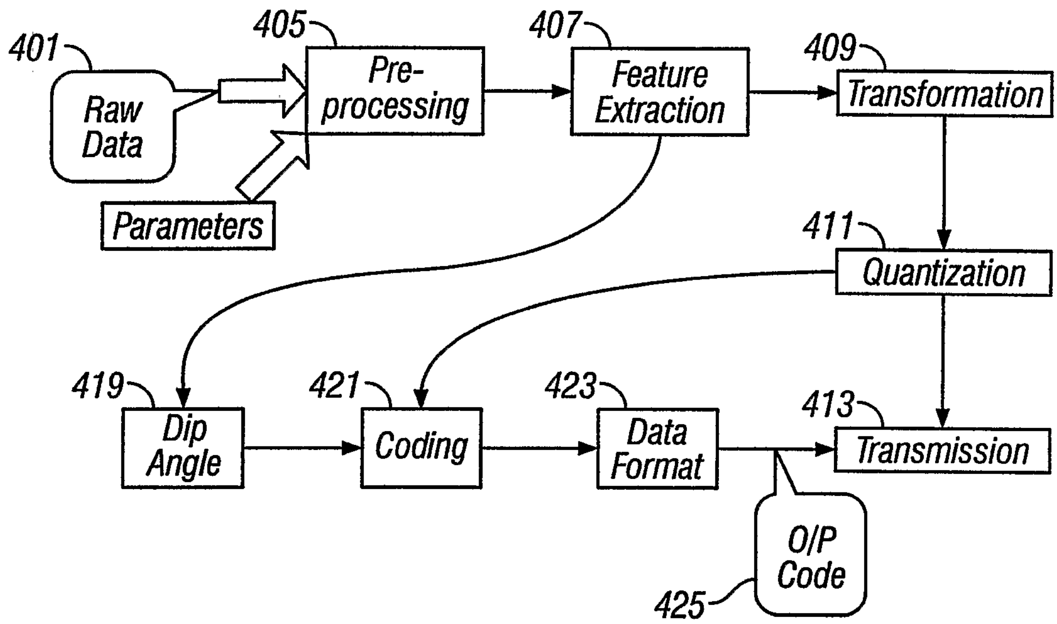

401
Raw Data
405
Pre-processing
Parameters
407
Feature Extraction
409
Transformation
411
Quantization
413
Transmission
419
Dip Angle
421
Coding
423
Data Format
O/P Code
425

FIG. 4

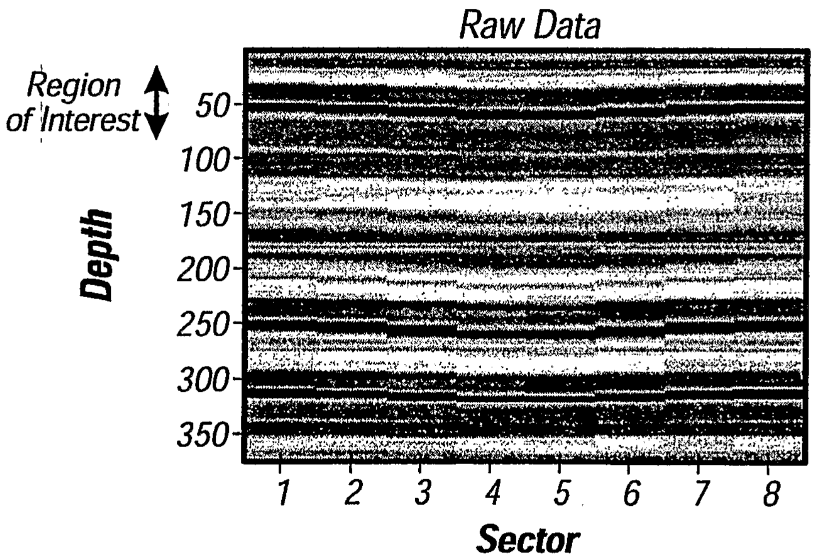
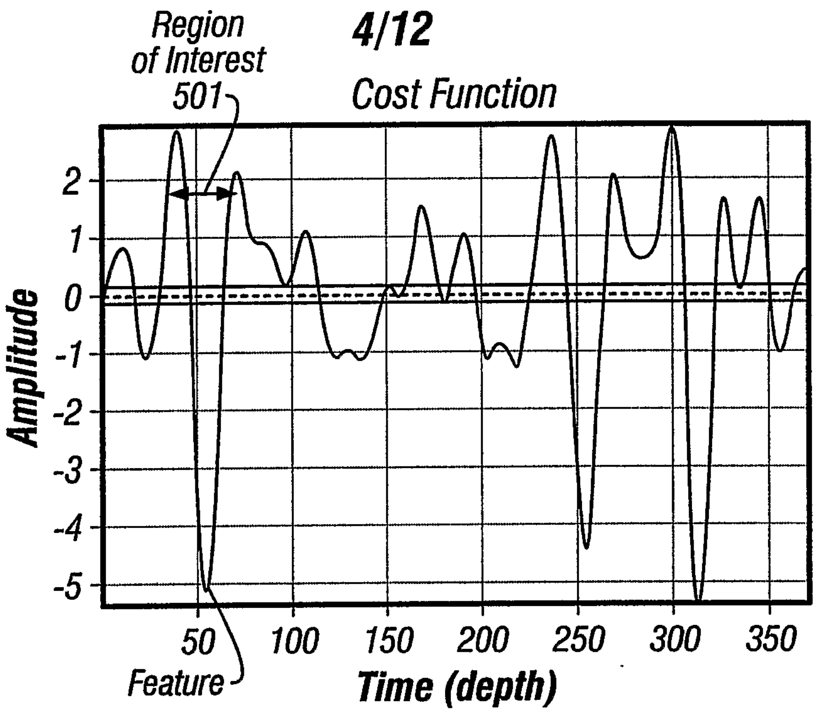
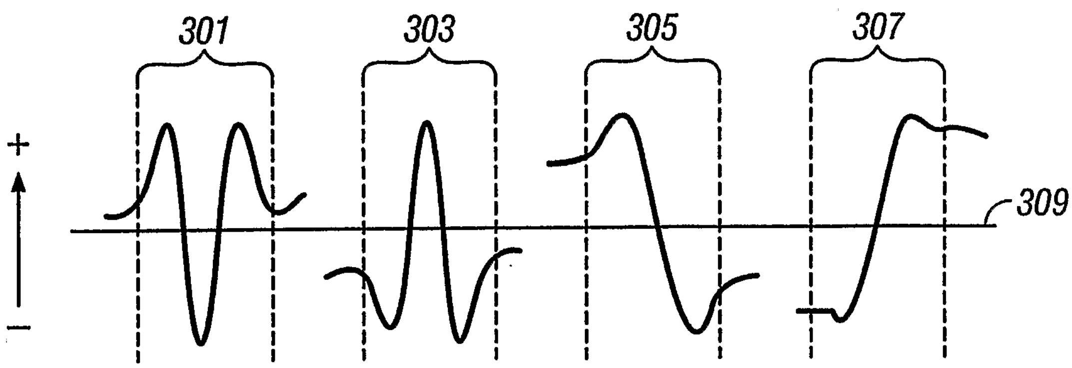

Raw Data
Region of Interest
Depth
50
100
150
200
250
300
350
1
2
3
4
5
6
7
8
Sector

FIG. 5A



Region of Interest 501
Cost Function
Amplitude
2
1
0
-1
-2
-3
-4
-5
50
100
150
200
250
300
350
Feature
Time (depth)

FIG. 5B



301
303
305
307
+
–
309

FIG. 5C

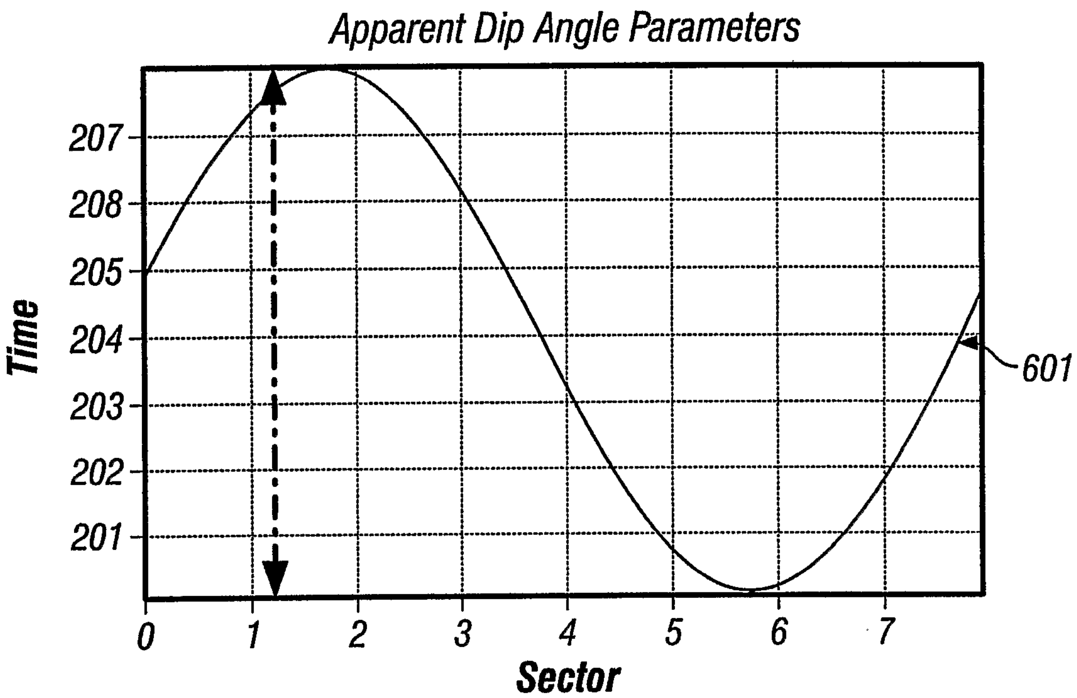

Apparent Dip Angle Parameters
207
208
205
204
203
202
201
Time
601
0
1
2
3
4
5
6
7
Sector

FIG. 6A

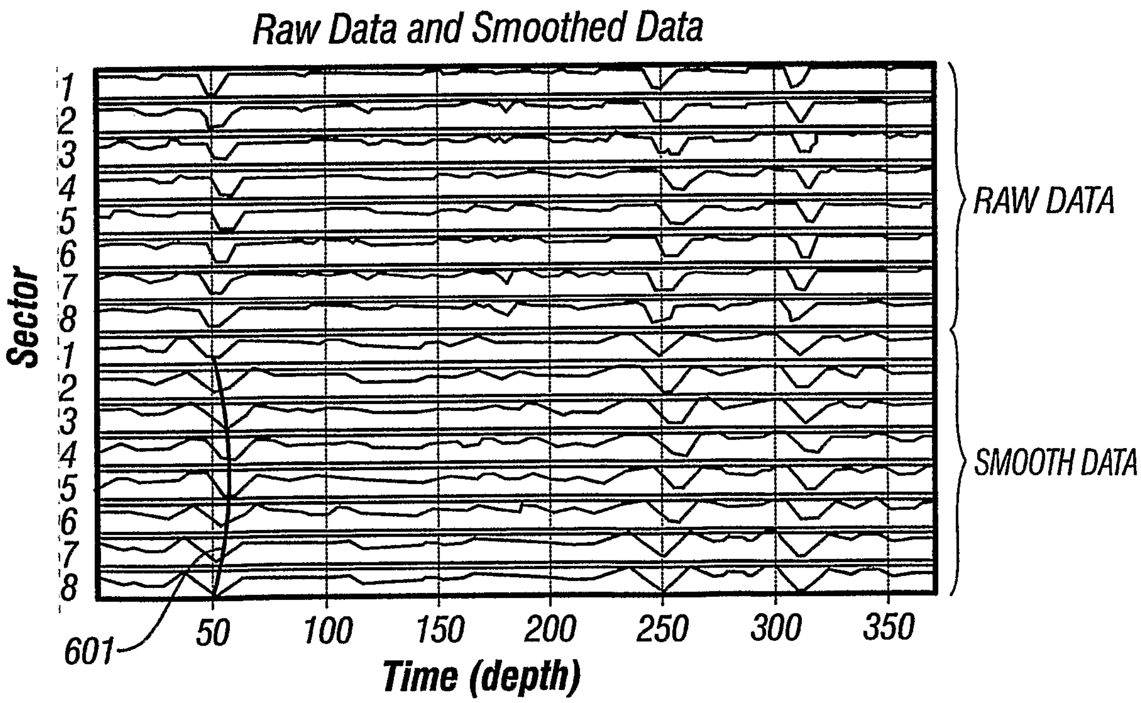

Raw Data and Smoothed Data
1
2
3
4
5
6
7
8
1
2
3
4
5
6
7
8
Sector
RAW DATA
SMOOTH DATA
601
50
100
150
200
250
300
350
Time (depth)

FIG. 6B

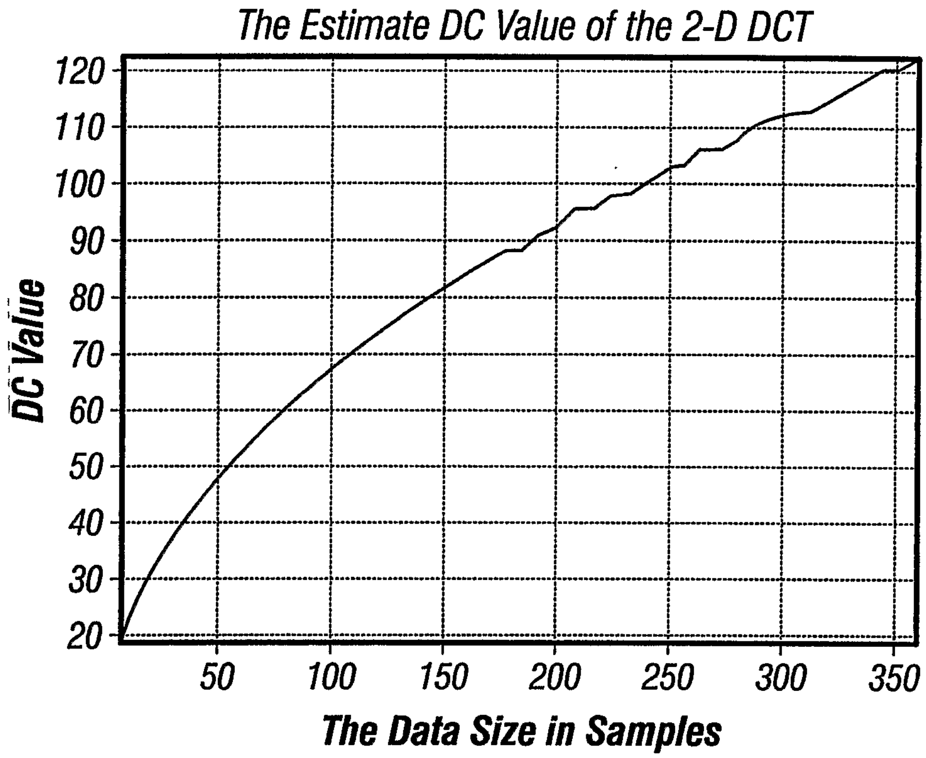

The Estimate DC Value of the 2-D DCT
DC Value
120
110
100
90
80
70
60
50
40
30
20
50
100
150
200
250
300
350
The Data Size in Samples

FIG. 7

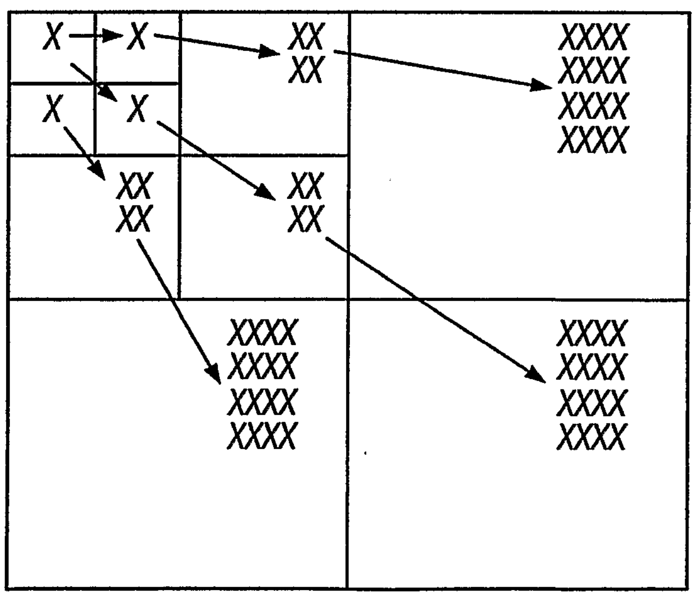

X
X
X
X
XX
XX
XX
XX
XX
XX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX

FIG. 8

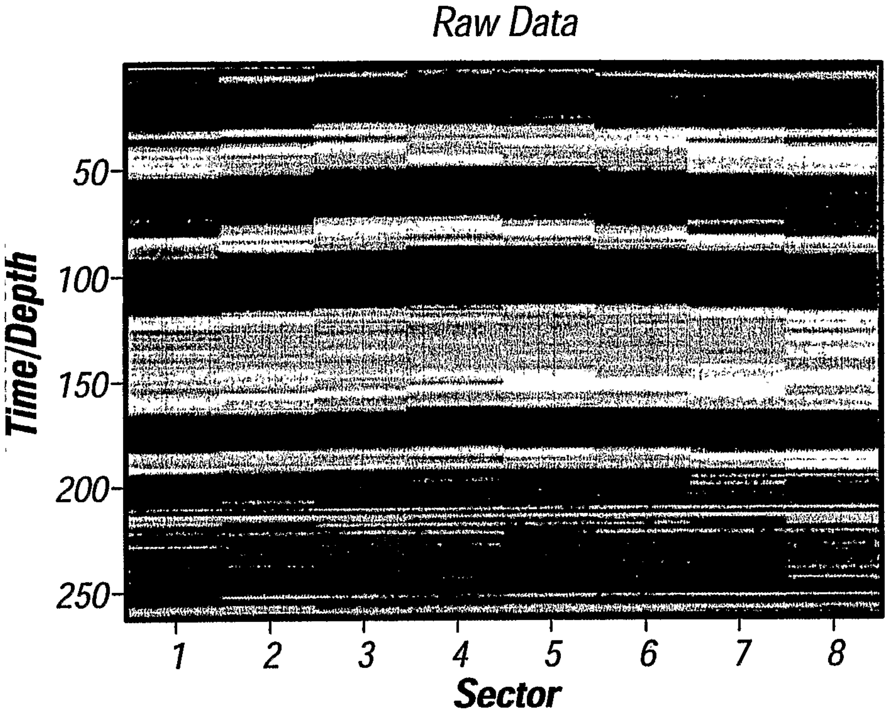

Raw Data
Time/Depth
50
100
150
200
250
1
2
3
4
5
6
7
8
Sector

FIG. 9

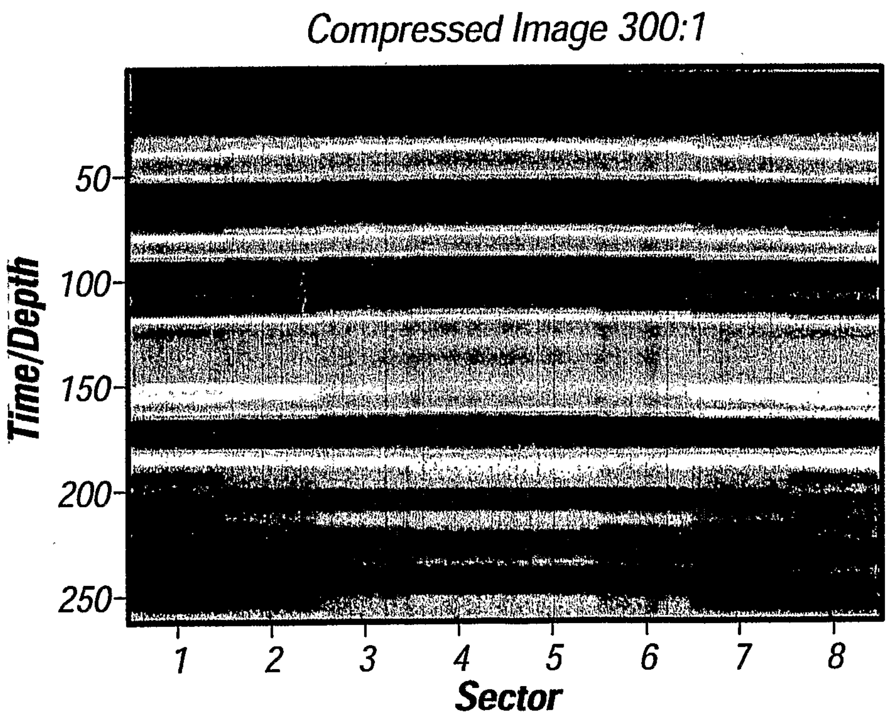

Compressed Image 300:1
Time/Depth
50
100
150
200
250
1
2
3
4
5
6
7
8
Sector

FIG. 10

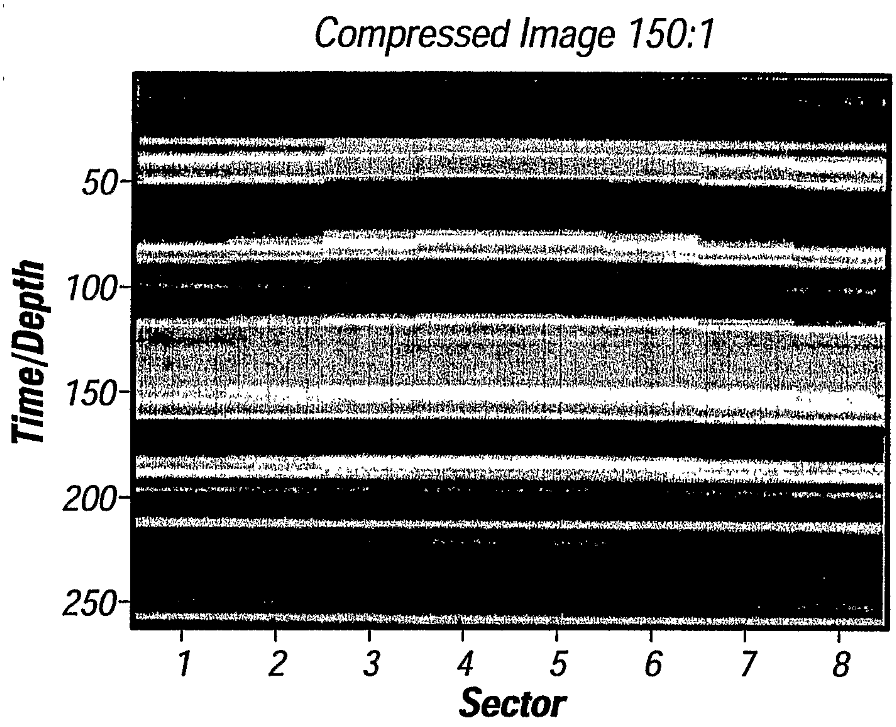

Compressed Image 150:1
Time/Depth
50
100
150
200
250
1
2
3
4
5
6
7
8
Sector

FIG. 11

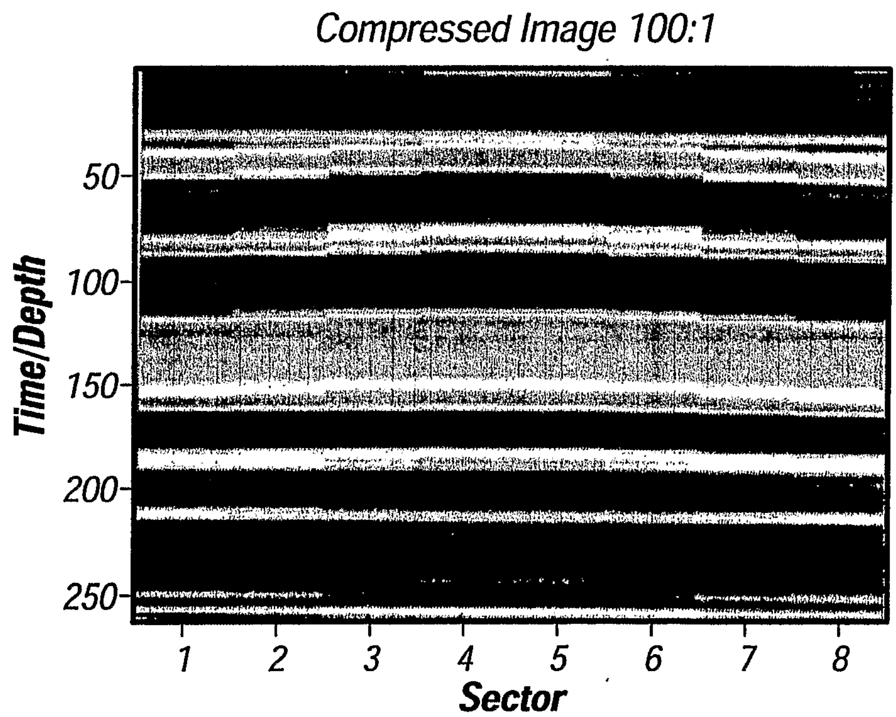

Compressed Image 100:1
Time/Depth
50
100
150
200
250
1
2
3
4
5
6
7
8
Sector

FIG. 12

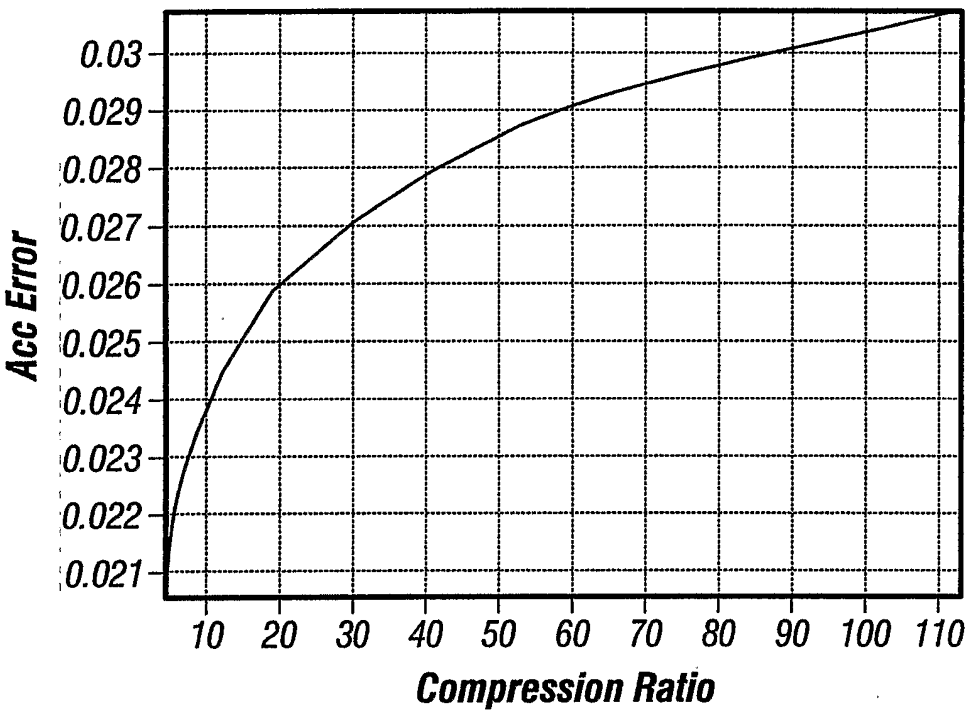

Acc Error
0.03
0.029
0.028
0.027
0.026
0.025
0.024
0.023
0.022
0.021
10 20 30 40 50 60 70 80 90 100 110
Compression Ratio

FIG. 13

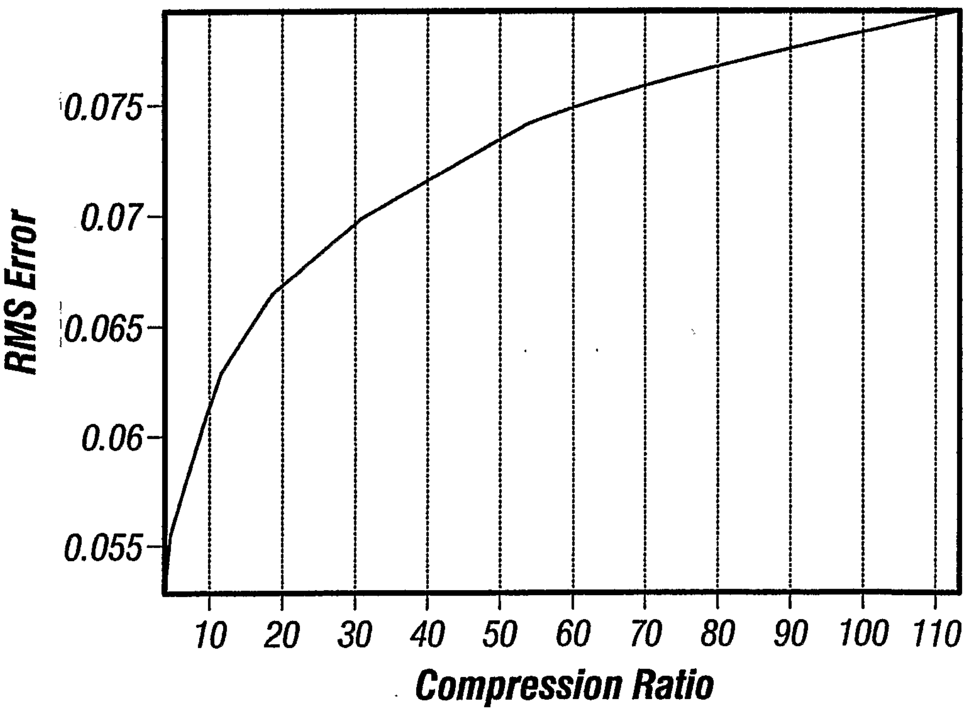

RMS Error
0.075
0.07
0.065
0.06
0.055
10 20 30 40 50 60 70 80 90 100 110
Compression Ratio

FIG. 14

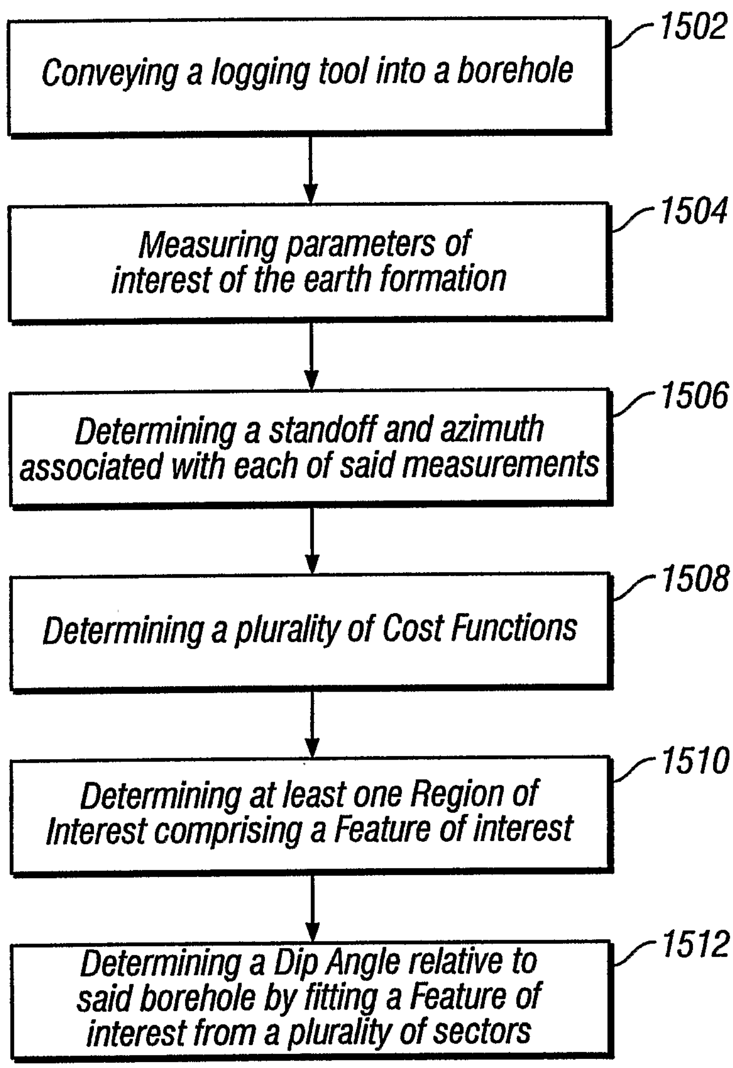

Conveying a logging tool into a borehole
1502
Measuring parameters of interest of the earth formation
1504
Determining a standoff and azimuth associated with each of said measurements
1506
Determining a plurality of Cost Functions
1508
Determining at least one Region of Interest comprising a Feature of interest
1510
Determining a Dip Angle relative to said borehole by fitting a Feature of interest from a plurality of sectors
1512

FIG. 15

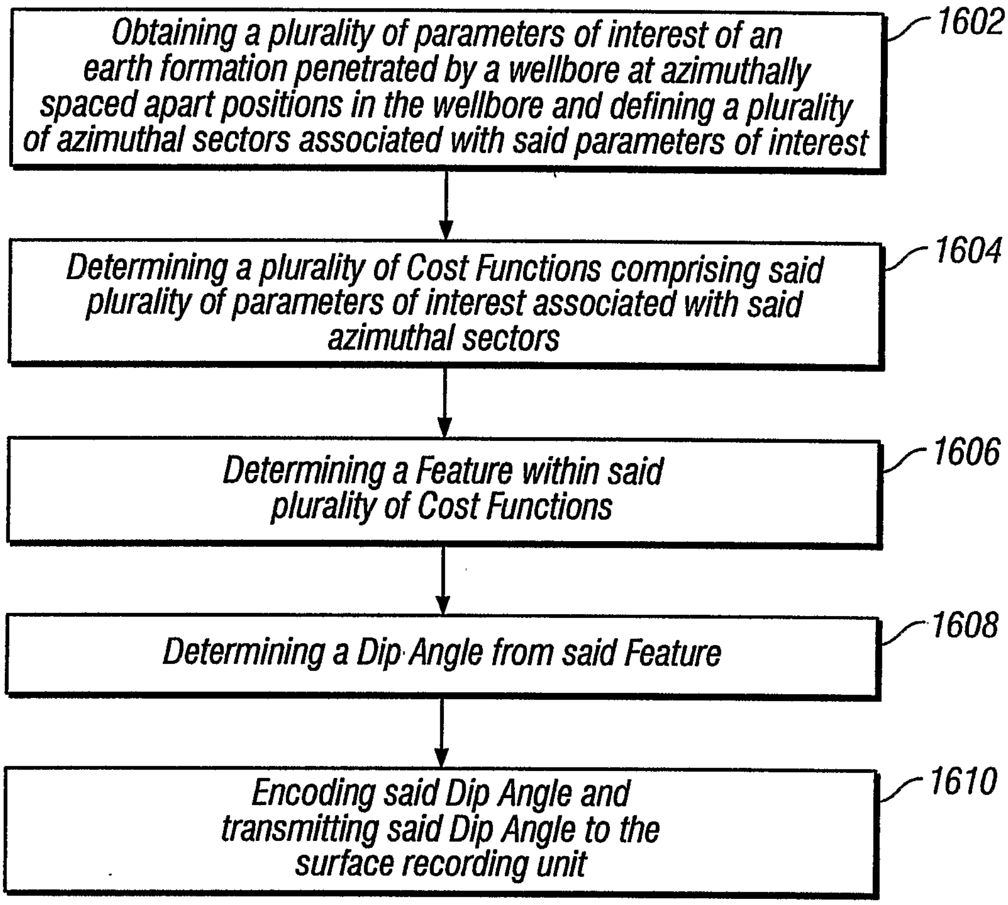

Obtaining a plurality of parameters of interest of an earth formation penetrated by a wellbore at azimuthally spaced apart positions in the wellbore and defining a plurality of azimuthal sectors associated with said parameters of interest
1602
Determining a plurality of Cost Functions comprising said plurality of parameters of interest associated with said azimuthal sectors
1604
Determining a Feature within said plurality of Cost Functions
1606
Determining a Dip Angle from said Feature
1608
Encoding said Dip Angle and transmitting said Dip Angle to the surface recording unit
1610

FIG. 16

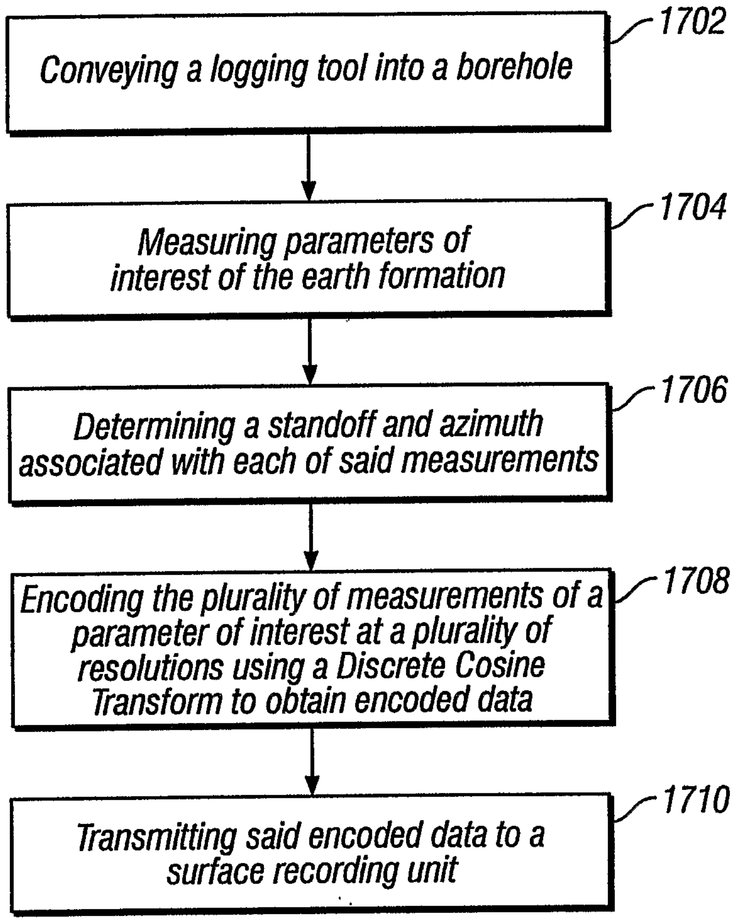

Conveying a logging tool into a borehole
1702
Measuring parameters of interest of the earth formation
1704
Determining a standoff and azimuth associated with each of said measurements
1706
Encoding the plurality of measurements of a parameter of interest at a plurality of resolutions using a Discrete Cosine Transform to obtain encoded data
1708
Transmitting said encoded data to a surface recording unit
1710

FIG. 17