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(54) Title: METHOD OF DEEP RESISTIVITY TRANSIENT MEASUREMENT WHILE DRILLING

(57) Abstract: A transient electromagnetic signal is recorded in an earth formation in the presence of a pipe having a finite conductivity. A portion of the signal dominated by the pipe signal is analyzed to determine a functional representation, extrapolated back to a time interval where the formation signal is present and subtracted from the recorded signal to provide a corrected signal.

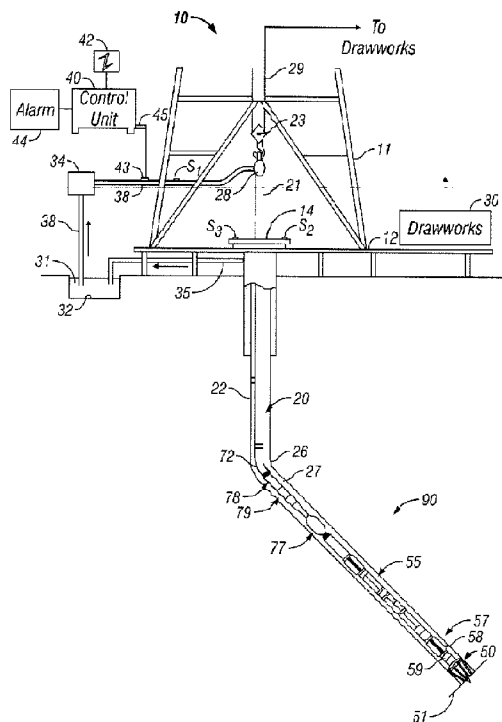


FIG. 1



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MC, MK, MT, NL, NO, PL, PT, RO, SE, SI, SK, SM,
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METHOD OF DEEP RESISTIVITY TRANSIENT MEASUREMENT WHILE DRILLING

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5 BACKGROUND OF THE DISCLOSURE

1. Field of the Disclosure

[0001] The disclosure is related to the field of electromagnetic induction well logging for determining the resistivity of earth formations penetrated by a wellbore. More
10 specifically, the disclosure relates to measuring the transient signals in an induction tool having a metallic pipe with finite, non-zero and high conductivity.

2. Description of the Related Art

[0002] Electromagnetic induction resistivity instruments can be used to determine the
15 electrical conductivity of earth formations surrounding a wellbore. An electromagnetic induction well logging instrument is described, for example, in U.S. Pat. No. 5,452,761 issued to *Beard* et al. The instrument described in the *Beard* '761 patent includes a transmitter coil and a plurality of receiver coils positioned at axially spaced apart locations along the instrument housing. An alternating current is passed
20 through the transmitter coil. Voltages which are induced in the receiver coils as a result of alternating magnetic fields induced in the earth formations are then measured. The magnitude of certain phase components of the induced receiver voltages are related to the conductivity of the media surrounding the instrument.

25 [0003] The development of deep-looking electromagnetic tools has a long history. Such tools are used to achieve a variety of different objectives. Deep looking tools attempt to measure the reservoir properties between wells at distances ranging from tens to hundreds of meters (ultra-deep scale). There are single-well and cross-well approaches, most of which are rooted in the technologies of radar/seismic wave
30 propagation physics. This group of tools is naturally limited by, among other things, their applicability to only high resistivity formations and the power available downhole.

[0004] Deep transient logging while drilling (LWD), especially “look-ahead” capability, was shown to have a great potential in predicting over-pressured zones, detecting faults in front of the drill bit in horizontal wells, profiling massive salt structures, etc. One of the main problems of deep transient measurements in LWD application is a parasitic signal due to the conductive drill pipe. A variety of techniques have been used to reduce this parasitic signal in the acquired data. For the purposes of the present disclosure, we adopt the following definition of the term “Transient Electromagnetic Method” from the Schlumberger Oilfield Glossary:

A variation of the electromagnetic method in which electric and magnetic fields are induced by transient pulses of electric current in coils or antennas instead of by continuous (sinusoidal) current.

[0005] Among the methods that have been used to reduce the parasitic signal due to a conductive drill pipe are using ferrite and copper shielding, using a reference signal (bucking) for calibration purposes, and using the asymptotic behavior of the conductive pipe time response to filter out the pipe signal.

[0006] U.S. Patent 7,027,922 to *Bespalov*, having the same assignee as the present disclosure and the contents of which are incorporated herein by reference is of particular interest. As disclosed in *Bespalov*, the transient signal may be represented by the Taylor Series expansion:

$$\begin{pmatrix} H_z(t_1) \\ H_z(t_2) \\ \vdots \\ H_z(t_{m-1}) \\ H_z(t_m) \end{pmatrix} = \begin{pmatrix} t_1^{-1/2} & t_1^{-3/2} & t_1^{-5/2} & \bullet & \bullet & \bullet & t_1^{n/2} \\ t_2^{-1/2} & t_2^{-3/2} & t_2^{-5/2} & \bullet & \bullet & \bullet & t_2^{n/2} \\ \bullet & \bullet & \bullet & \bullet & \bullet & \bullet & \bullet \\ \bullet & \bullet & \bullet & \bullet & \bullet & \bullet & \bullet \\ \bullet & \bullet & \bullet & \bullet & \bullet & \bullet & \bullet \\ t_{m-1}^{-1/2} & t_{m-1}^{-3/2} & t_{m-1}^{-5/2} & \bullet & \bullet & \bullet & t_{m-1}^{n/2} \\ t_m^{-1/2} & t_m^{-3/2} & t_m^{-5/2} & \bullet & \bullet & \bullet & t_m^{n/2} \end{pmatrix} \begin{pmatrix} S_{1/2} \\ S_{3/2} \\ S_{5/2} \\ \bullet \\ \bullet \\ \bullet \\ S_{(2n-1)/2} \end{pmatrix}$$

Where H_z is the z- component of the magnetic field, t is the time and the S -s are expansion coefficients. As discussed in *Bespalov*, the $S_{1/2}$ and $S_{3/2}$ terms are dominated by the effects of the conductive pipe, and estimating and correcting for at least the $S_{1/2}$ component and, optionally, also the $S_{3/2}$ component gives a transient response that is sensitive to the distance to bed boundaries.

[0007] In case the target DOI of up to 50 meters the conductive pipe signal is typically more than two orders of magnitude greater than the formation signal even if the ferrite and copper shields are used. Under these conditions, the accuracy of bucking (e.g. due to exposure to the down-hole conditions), and asymptotic filtering may not be sufficient to facilitate measurements. The present disclosure addresses the problems for extra deep resistivity measurements.

SUMMARY OF THE DISCLOSURE

[0008] One embodiment of the disclosure is a method of evaluating an earth formation using a tool conveyed within a borehole in the earth formation. The tool has a body with a finite, non-zero conductivity. The method includes using a transmitter on the tool for producing a transient electromagnetic signal in the earth formation; using at least one receiver for receiving a signal resulting from interaction of the transient signal with the earth formation, the received signal has a first time interval that includes a first component responsive to a property of the earth formation and a second component responsive to the conductivity of the tool, and has a second time interval responsive substantially to the conductivity of the tool; using the received signal in the second time interval and the received signal in the first time interval to estimate the first component of the signal in the first time interval.

[0009] Another embodiment of the disclosure is an apparatus configured to evaluate an earth formation. The apparatus includes a tool having a body with a finite, non-zero conductivity configured to be conveyed in a borehole; a transmitter on the tool configured to produce a transient electromagnetic signal in the earth formation; at least one receiver configured to produce a signal responsive to interaction of the transient signal with the earth formation. The signal has a first time interval including a first component responsive to a property of the earth formation and a second component responsive to the conductivity of the tool, and has a second time interval responsive substantially to the conductivity of the tool. The apparatus also includes at least one processor configured to use the produced signal in the second time interval and the produced signal in the first time interval to estimate the first component of the signal in the first time interval.

[0010] Another embodiment of the disclosure is a computer-readable medium accessible to at least one processor. The medium includes instructions which enable

the at least one processor to process a signal produced by a receiver on a tool in a borehole responsive to a transient signal generated by a transmitter in the borehole to estimate a property of the earth formation. The signal has a first time interval including a first component responsive to a property of the earth formation and a
5 second component responsive to a conductivity of the tool, and has a second time interval responsive substantially to the conductivity of the tool

BRIEF DESCRIPTION OF THE DRAWINGS

[0011] The present disclosure is best understood with reference to the accompanying
10 figures in which like numbers refer to like elements and in which:

FIG. 1 shows a resistivity logging instrument according to the present disclosure conveyed in a borehole;

FIG. 2 shows a typical cylindrical wellbore configuration for oil exploration.

FIG. 3 shows a cylindrical model of the borehole configuration;

15 FIG. 4 (prior art) shows transient responses due to the remote cylindrical boundary in the configuration of Fig. 3 in the presence of a perfectly conducting drill pipe;

FIG. 5 (prior art) shows transient responses due to a remote boundary when the drill pipe has a conductivity $\sigma=1.4 \cdot 10^6$ S/m;

20 FIG. 6 shows transient responses over a time interval where the signal is dominated by the effect of a conducting drill pipe;

FIG. 7 shows a flow chart illustrating some of the steps of the present disclosure;

FIG. 8 shows an exemplary transient signal that includes a formation signal,
25 pipe signal and noise; and

FIG. 9 shows the result of applying the method of the present disclosure to the signal of FIG. 8.

DESCRIPTION OF EXEMPLARY EMBODIMENTS

30 [0012] Figure 1 shows a schematic diagram of a drilling system 10 with a drillstring 20 carrying a drilling assembly 90 (also referred to as the bottomhole assembly, or "BHA") conveyed in a "wellbore" or "borehole" 26 for drilling the wellbore. The drilling system 10 includes a conventional derrick 11 erected on a floor 12 which supports a rotary table 14 that is rotated by a prime mover such as an electric motor

(not shown) at a desired rotational speed. The drillstring **20** includes a tubing such as a drill pipe **22** or a coiled-tubing extending downward from the surface into the borehole **26**. The drillstring **20** is pushed into the wellbore **26** when a drill pipe **22** is used as the tubing. For coiled-tubing applications, a tubing injector, such as an injector (not shown), however, is used to move the tubing from a source thereof, such as a reel (not shown), to the wellbore **26**. The drill bit **50** attached to the end of the drillstring breaks up the geological formations when it is rotated to drill the borehole **26**. If a drill pipe **22** is used, the drillstring **20** is coupled to a drawworks **30** via a Kelly joint **21**, swivel **28**, and line **29** through a pulley **23**. During drilling operations, the drawworks **30** is operated to control the weight on bit, which is an important parameter that affects the rate of penetration. The operation of the drawworks is well known in the art and is thus not described in detail herein.

[0013] During drilling operations, a suitable drilling fluid **31** from a mud pit (source) **32** is circulated under pressure through a channel in the drillstring **20** by a mud pump **34**. The drilling fluid passes from the mud pump **34** into the drillstring **20** via a desurger (not shown), fluid line **28** and Kelly joint **21**. The drilling fluid **31** is discharged at the borehole bottom **51** through an opening in the drill bit **50**. The drilling fluid **31** circulates uphole through the annular space **27** between the drillstring **20** and the borehole **26** and returns to the mud pit **32** via a return line **35**. The drilling fluid acts to lubricate the drill bit **50** and to carry borehole cutting or chips away from the drill bit **50**. A sensor S_1 may be placed in the line **38** to provide information about the fluid flow rate. A surface torque sensor S_2 and a sensor S_3 associated with the drillstring **20** respectively provide information about the torque and rotational speed of the drillstring. Additionally, a sensor (not shown) associated with line **29** is used to provide the hook load of the drillstring **20**.

[0014] In one embodiment of the disclosure, the drill bit **50** is rotated by only rotating the drill pipe **22**. In another embodiment of the disclosure, a downhole motor **55** (mud motor) is disposed in the drilling assembly **90** to rotate the drill bit **50** and the drill pipe **22** is rotated usually to supplement the rotational power, if required, and to effect changes in the drilling direction.

[0015] In one embodiment of **Figure 1**, the mud motor **55** is coupled to the drill bit **50** via a drive shaft (not shown) disposed in a bearing assembly **57**. The mud motor rotates the drill bit **50** when the drilling fluid **31** passes through the mud motor **55** under pressure. The bearing assembly **57** supports the radial and axial forces of the drill bit. A stabilizer **58** coupled to the bearing assembly **57** acts as a centralizer for the lowermost portion of the mud motor assembly.

[0016] In one embodiment of the disclosure, a drilling sensor module **59** is placed near the drill bit **50**. The drilling sensor module contains sensors, circuitry and processing software and algorithms relating to the dynamic drilling parameters. Such parameters may include bit bounce, stick-slip of the drilling assembly, backward rotation, torque, shocks, borehole and annulus pressure, acceleration measurements and other measurements of the drill bit condition. A suitable telemetry or communication sub **72** using, for example, two-way telemetry, is also provided as illustrated in the drilling assembly **90**. The drilling sensor module processes the sensor information and transmits it to the surface control unit **40** via the telemetry system **72**.

[0017] The communication sub **72**, a power unit **78** and an MWD tool **79** are all connected in tandem with the drillstring **20**. Flex subs, for example, are used in connecting the MWD tool **79** in the drilling assembly **90**. Such subs and tools form the bottom hole drilling assembly **90** between the drillstring **20** and the drill bit **50**. The drilling assembly **90** makes various measurements including the pulsed nuclear magnetic resonance measurements while the borehole **26** is being drilled. The communication sub **72** obtains the signals and measurements and transfers the signals, using two-way telemetry, for example, to be processed on the surface. Alternatively, the signals can be processed using a downhole processor in the drilling assembly **90**.

[0018] The surface control unit or processor **40** also receives signals from other downhole sensors and devices and signals from sensors **S₁-S₃** and other sensors used in the system **10** and processes such signals according to programmed instructions provided to the surface control unit **40**. The surface control unit **40** displays desired drilling parameters and other information on a display/monitor **42** utilized by an operator to control the drilling operations. The surface control unit **40** may include a

computer or a microprocessor-based processing system, memory for storing programs or models and data, a recorder for recording data, and other peripherals. The control unit 40 may be configured to activate alarms 44 when certain unsafe or undesirable operating conditions occur.

5

[0019] Figure 2 shows an exemplary cylindrical structure, comprising three zones substantially defined by a metal pipe 200 with conductivity σ_1 , and two layers 203, and 205 with conductivities σ_2 , and σ_3 , respectively. The magnetic permeability of the entire space is μ . As illustrated, the cylindrical boundary 202 separating the metal pipe from the transition layer and the cylindrical boundary 204 separating the regions of transition layer and remote formation share a common z-axis 210. As measured from the z-axis, the radius of boundary 202 is labeled as r_{md} , and the radius of boundary 204 is labeled as r_{tl} . An electromagnetic field is excited by a transmitter current loop 215 of radius, r_{xt} , and is measured by a receiver loop 220 of radius r_{xr} . Transmitter loop and receiver loop are separated by distance L . The amplitude and frequency of the AC transmitter current are I and ω , respectively.

[0020] There is only one component E_ϕ of the electric field in the considered model of Fig. 2, and it satisfies the Maxwell's equation detailed in Eq. (1) under the conditions of Eq. (2):

$$\frac{1}{r} \frac{\partial}{\partial r} \left(r \frac{\partial E_\phi}{\partial r} \right) - \frac{E_\phi}{r^2} + \frac{\partial^2 E_\phi}{\partial z^2} = k^2 E_\phi \quad (1)$$

$$\text{where } k_j^2 = -i\omega\mu\sigma_j, j = 1, 2, 3 \quad (2)$$

As is well known in the art, boundary conditions require a continuity of the tangential electric field E_ϕ , and of the tangential magnetic field, H_z , at boundaries 202 and 204.

These conditions may be expressed mathematically in the form:

$$\left\{ \begin{array}{l} [E_\phi] = 0 \\ \left[\frac{\partial E_\phi}{\partial r} \right] = 0 \end{array} \right\} \text{ at } r = r_{mn}, r_{tl} \quad (3)$$

An analytical solution for the boundary value problem of Eqs. (1) and (3), may be found using known techniques of the Fourier transform and separation of variables. The resulting expressions for an electromotive force induced in the receiver, $E_f =$

$2\pi r_{xt} E_\phi$, are shown below:

$$E_f = \int_0^\infty (F_a + F_b) \cos(\lambda L) d\lambda + \frac{i\omega\mu(2\pi r_{xt})(2\pi r_{xr})}{2\pi} \int_0^\infty \frac{\lambda}{2p_2} e^{-p_2 L} J_1(\lambda r_{xt}) J_1(\lambda r_{xr}) d\lambda \quad (4)$$

$$F_a = \frac{i\omega\mu(2\pi r_{xt})(2\pi r_{xr})}{2\pi^2 Det} \left[\frac{I_1(p_2 * r_{md})}{K_1(p_2 * r_{md})} \frac{K_1(p_2 * r_{tl})}{I_1(p_2 * r_{tl})} K_1(p_2 * r_{xt}) I_1(p_2 * r_{xt}) \frac{\alpha_{11}\alpha_{22}}{\alpha_{12}\alpha_{21}} \right. \\ \left. - \frac{K_1(p_2 * r_{tl})}{I_1(p_2 * r_{tl})} I_1(p_2 * r_{xt}) I_1(p_2 * r_{xr}) \frac{\alpha_{22}}{\alpha_{21}} \right] \quad (5)$$

$$F_b = \frac{i\omega\mu(2\pi r_{xt})(2\pi r_{xr})}{2\pi^2 Det} \left[\frac{I_1(p_2 * r_{md})}{K_1(p_2 * r_{md})} \frac{K_1(p_2 * r_{tl})}{I_1(p_2 * r_{tl})} I_1(p_2 * r_{xt}) K_1(p_2 * r_{xt}) \frac{\alpha_{11}\alpha_{22}}{\alpha_{12}\alpha_{21}} \right. \\ \left. - \frac{I_1(p_2 * r_{md})}{K_1(p_2 * r_{md})} K_1(p_2 * r_{xt}) K_1(p_2 * r_{xr}) \frac{\alpha_{11}}{\alpha_{12}} \right] \quad (6)$$

$$p_j^2 = k_j^2 + \lambda_j^2 \quad (7)$$

$$5 \quad \alpha_{11} = 1 - \frac{p_2}{p_1} \frac{I_1(p_1 * r_{md})}{I_0(p_1 * r_{md})} \frac{I_0(p_2 * r_{md})}{I_1(p_2 * r_{md})} \quad (8)$$

$$\alpha_{12} = 1 + \frac{p_2}{p_1} \frac{I_1(p_1 * r_{md})}{I_0(p_1 * r_{md})} \frac{K_0(p_2 * r_{md})}{K_1(p_2 * r_{md})} \quad (9)$$

$$\alpha_{21} = 1 + \frac{p_2}{p_3} \frac{K_1(p_3 * r_{tl})}{K_0(p_3 * r_{tl})} \frac{I_0(p_2 * r_{tl})}{I_1(p_2 * r_{tl})}$$

(10)

$$\alpha_{22} = 1 - \frac{p_2}{p_3} \frac{K_1(p_3 * r_{tl})}{K_0(p_3 * r_{tl})} \frac{K_0(p_2 * r_{tl})}{K_1(p_2 * r_{tl})}$$

10 (11)

$$Det = 1 - \frac{I_1(p_2 * r_{md})}{K_1(p_2 * r_{md})} \frac{K_1(p_2 * r_{tl})}{I_1(p_2 * r_{tl})} \frac{\alpha_{11}\alpha_{22}}{\alpha_{12}\alpha_{21}}$$

(12)

The transient responses are obtained by generating a step function of electric current
15 in the transmitter antenna. Then the response in time domain $E_f(t)$ can be obtained
by applying Fourier transform to the frequency response (4):

$$E_f(t) = \frac{2}{\pi} \int_0^\infty \text{Im}[E_f(\omega)] \cdot \frac{\sin(\omega t)}{\omega} d\omega = \frac{2}{\pi} \int_0^\infty \text{Re}[E_f(\omega)] \cdot \frac{\cos(\omega t)}{\omega} d\omega$$

(13)

5 [0021] **Figure 3** shows a practical example of the cylindrical model with two formation layers: 50 Ω -m formation shown at **302** and 2 Ω -m formation shown at **304**. **Figure 4** shows the responses at a distance to boundary of 1, 2, 4, 6, 8, and 10 meters are shown as **401**, **402**, **403**, **404**, **405**, and **406**, respectively. The response for an infinite distance is shown as **407**.

10 [0022] **Figure 5** shows the transient responses obtained in the presence of a typical conductive pipe. The conductivity is $\sigma=1.4 \times 10^6$ S/m. Curves **501**, **502**, and **503**, indicate responses at distances of 1, 2, and 4 meters to a remote boundary. Response curve **504** represents the response to a remote boundary at an infinite distance. Response curve **504** is nearly indistinguishable from and overlaps response curves at a distance of 6m, 8m, and 10m. **Figure 5** illustrates the fact that at late times corresponding to deep investigation the conductive pipe signal typically dominates the transient response of the earth's formations by at least an order of magnitude. The

15 main part of the conductive pipe signal can be removed from received signal by using one of the following: modeling results for the pipe signal in air, lab measurements of the pipe signal, and by using bucking coil. In practice, there will be always a part of the pipe signal left due to instability of the pipe signal caused by drilling environment. The causes of the instability can be temperature dependence of electric conductivity

20 of the pipe, changing effective distance between the transmitter and the receiver due to bending of the drill pipe, changing effective cross-sectional area of the receiver and transmitter and others. The instability of pipe signal may produce low frequency noise comparable or exceeding the formation signal especially at late times.

25 [0023] The present disclosure teaches the elimination of the signal from conductive drill pipe in transient EM data based on acquiring an additional set of data at a late time interval beyond the time interval of interest. Due to faster decay of the formation signal the additionally acquired data contain negligible (less than a tolerable systematic error) portion of the formation signal, and therefore represents the response

30 of only the drill pipe. The estimated drill pipe signal is then extrapolated back to the time interval of interest (typically 0.01-1 ms for the deep reading transient measurements) and subtracted from the receiver data. The extrapolation procedure may be applied to the drill pipe signal or to the drill pipe signal residuals remaining

after a calibration procedure or after applying a bucking technique. Details of the method are discussed next.

[0024] Figure 6 shows a typical time-domain signal of a drill pipe 601 and a formation signal 603 for homogeneous medium with conductivity 0.1 S/m. Denoting by (t_1, t_2) the time interval of interest for the formation signal, in the example shown it can be seen that if the time t_2 is 1 ms, then the formation signal at time t_2 exceeds the formation signal at $t = 6ms$ by more than two orders of magnitude. In the example shown in Figure 6, the values of t_1 and t_2 are 10^{-5} s and 10^{-3} s respectively. It is then assumed that the two orders of magnitude signal of drill pipe-formation signal ratio is sufficient to neglect the formation signal in a time interval (t_3, t_4) . In the example shown, the values of t_3 and t_4 are 6×10^{-3} s and 10^{-2} s respectively. It is also assumed that the pipe voltage signal f in the receiver coil can be represented by known function of time t and a parameter vector $\vec{\beta}$. Then the drill pipe signal in the main data acquisition interval (t_1, t_2) can be obtained from extrapolation of the data obtained in the additional time interval (t_3, t_4) . The following procedure can be used for the extrapolation.

[0025] The parameter vector $\vec{\beta}$ of the model function $f(t, \vec{\beta})$ can be determined by employing a least squares technique:

$$\sum_i |V_{pi} - f(t_i, \vec{\beta})|^2 \rightarrow \min, \quad t_i \in (t_3, t_4), \quad (14)$$

Here V_{pi} is the data vector acquired in the time interval (t_3, t_4) .

The model function $f(t, \vec{\beta})$ can be presented as a linearization with respect to the parameter vector:

$$f(t_i, \vec{\beta}) \approx f(t_i, \vec{\beta}_0) + \sum_j g(t_i) \Delta \beta_j, \quad (15)$$

where $f(t_i, \vec{\beta}_0)$ is a known function of a nominal value of the parameter $\vec{\beta}$ from calibration, $\Delta \beta_j$ are small variations of the parameters from their nominal values $\vec{\beta}_0$,

and $g(t_i)$ are known time dependent coefficients – derivatives $\frac{\partial f(t_i, \vec{\beta})}{\partial \beta_j}$. The possibility of linearization is practically enabled by the fact that the main part of the pipe signal is known either from modeling, or lab measurements (calibration procedure). It can be also measured (and subtracted from the receiver data) based on
 5 using a bucking coil. Then coefficients $g(t_i)$ can also be obtained beforehand from modeling or lab measurements.

Then a linear least squares procedure can be used to determine variations $\Delta\beta_j$ of parameters β_j from the calibrated data V_{pci} :

$$\sum_i \left| V_{pci} - \sum_j g(t_i) \cdot \Delta\beta_j \right|^2 \xrightarrow{LLS} \min, \quad t_i \in (t_3, t_4), \quad (16)$$

10

Solution of the least squares problem (3) gives the parameter estimator $\Delta\hat{\beta}_j$ for each parameter variation. Then the estimated current value of the conductive pipe signal residuals in the interval of interest (t_1, t_2) can be determined and then subtracted from the receiver data:

15

$$Data' = Data - \sum_j g(t_i) \Delta\hat{\beta}_j. \quad (17)$$

[0026] The calibration signal may be obtained by making measurements with the tool suspended in air. Transient signals are measured and using a selected fitting function,
 20 nominal values of the fitting parameters are derived by performing a least-squares fit to the measured calibration signal using the selected fitting function. The nominal values of the fitting parameter are then used in the linearized method discussed above. Using the calibration signal may avoid problems with non-uniqueness of the fitting.

25 [0027] In one embodiment of the disclosure, the function $f(t, \vec{\beta})$ is an exponential function of two parameters β_1 and β_2 given by:

$$f(t_i, \vec{\beta}) = \beta_1 e^{-\beta_2 t_i} \quad (18).$$

Such a representation is given as a simplified example and may be adequate to represent the response of a conductive drill pipe having a single diameter, thin wall

and a single conductivity. For a more practical case where the portion of the drill pipe that contributes to the transient signal can be represented by the equations (5)-(13) for $\sigma_2 = \sigma_3 = 0$.

5 [0028] A flow chart of some of the steps of the present disclosure is shown in **Figure 7**. Transient electromagnetic data are acquired over a time that exceeds the time of interest **701** for formation signals. This includes a time interval from t_1 (the first time of interest for the formation signal) to t_4 (the end of a time interval over which the drill pipe signal is dominant). This includes a first time interval $\{t_1, t_2\}$ where the
 10 signal is responsive to both the formation property and to the drill pipe, and a second time interval $\{t_3, t_4\}$ where the signal is responsive almost entirely to the pipe. A fitting function for the pipe signal is defined and linearized **703** near the nominal values of the pipe parameters. A least squares fit to data over the second time interval $\{t_3, t_4\}$ **705** is then carried out **709** to estimate a modified (by drilling environment)
 15 vector of parameter. Using the fitting parameters obtained at **709**, the pipe signal is extrapolated to the first time interval $\{t_1, t_2\}$ **711** and then subtracted **717** from the signal over the time interval $\{t_1, t_2\}$ **717** to give a corrected signal for the interval $\{t_1, t_2\}$ **719**. The corrected signal may be estimated for a plurality of different transmitter-receiver distances, and using prior art methods, such as a table lookup, the distance to
 20 the bed boundary may be estimated.

[0029] Turning now to **Figure 8**, an exemplary transient signal **803** is shown that includes a formation signal, pipe signal and additive measurement noise. For the example shown, the transmitter-receiver distance was 10 m and the formation
 25 conductivity was 0.1 S/m. Also shown in **Figure 8** is the signal that would be recorded in the absence of the pipe **801** (or with a pipe of infinite conductivity). The time interval of interest is from 10^{-5} s to 10^{-3} s. As can be seen, the pipe signal starts becoming important after about 3×10^{-4} s, denoted by **805**.

30 [0030] The result of applying the method of the present disclosure is shown in **Figure 9**. The curve **903** shows the result of doing a least squares fit to the signal **903** over the time interval $\{t_3, t_4\}$, extrapolating back to the time interval of interest, and subtracting it from the original signal **803**. As can be seen, the resultant curve is very

close to the formation signal over the entire interval $\{t_1, t_2\}$ and can thus be inverted using prior art methods to give the formation properties, including conductivities and distance to an interface in the earth formation.

5 **[0031]** The disclosure has been described above with reference to a MWD apparatus carried on a drillstring. The method of the disclosure can also be used on other types of MWD apparatus conveyed on a drilling tubular, and may also be used on a logging tool carried on a wireline. The last such method is of relatively minor importance since on wireline devices, it is possible to have a housing of very high conductivity so
10 that the correction methods described herein may not be necessary. Such means of conveyance would be known to those versed in the art and are not discussed further.

[0032] It should be further noted that while the example given about used axially oriented transmitters and receivers, this is not to be construed as a limitation. The
15 method disclosed above may also be used with a transmitter and/or receiver oriented at an angle to the longitudinal axis of the logging tool. Specifically, using measurements made with axially oriented and transverse antennas as discussed in U.S. 7,167,006 to *Itskovich*, it is possible to get an accurate estimate of a distance to an interface and use it for reservoir navigation. The interface may be a gas-oil
20 interface, an oil-water interface, a gas-water interface and/or a bed boundary. The estimated distance may be used for controlling a direction of drilling.

[0033] Implicit in the processing of the data is the use of a computer program on a suitable machine-readable medium that enables the processor to perform the control
25 and processing. The machine-readable medium may include ROMs, EPROMs, EEPROMs, Flash Memories and Optical disks.

[0034] While the foregoing disclosure is directed to the specific embodiments of the disclosure, various modifications will be apparent to those skilled in the art. It is
30 intended that all such variations within the scope and spirit of the appended claims be embraced by the foregoing disclosure.

CLAIMS

What is claimed is:

- 1 1. A method of evaluating an earth formation using a tool conveyed within a
2 borehole in the earth formation, the tool having a body with a finite, non-zero
3 conductivity, the method comprising:
4 using a transmitter on the tool for producing a transient
5 electromagnetic signal in the earth formation;
6 using at least one receiver for receiving a signal resulting from
7 interaction of the transient signal with the earth formation, the received signal
8 comprising a first time interval including a first component responsive to a
9 property of the earth formation and a second component responsive to the
10 conductivity of the tool, and a second time interval responsive substantially to
11 the conductivity of the tool;
12 using the received signal in the second time interval and the received
13 signal in the first time interval to estimate the first component of the signal in
14 the first time interval.
15
- 1 2. The method of claim 1 further comprising using the estimated first component
2 of the signal for estimating a value of the property of the earth formation.
3
- 1 3. The method of claim 1 wherein said parameter of interest is at least one of (i) a
2 resistivity property of the formation, and (ii) a distance to a bed boundary in
3 the formation.
4
- 1 4. The method of claim 1 wherein estimating the first component of the signal in
2 the first time interval further comprises:
3 (i) performing a least squares fit to the signal in the second time
4 interval;
5 (ii) using fitting parameters derived in the least squares fit to define an
6 extrapolated signal in the first time interval; and
7 (iii) subtracting the extrapolated signal from the first signal.
8

- 1 5. The method of claim 4 wherein performing the least-squared fit further
2 comprises using an exponential function.
3
- 1 6. The method of claim 4 wherein performing the least squares fit to the second
2 time interval of the signal further comprises:
3 (i) defining a fitting function, and
4 (ii) linearizing the fitting function about a nominal value of a fitting
5 parameter.
6
- 1 7. The method of claim 6 further comprising estimating the nominal value of the
2 fitting parameter using a calibration signal
3
- 1 8. The method of claim 1 further comprising conveying the tool into the earth
2 formation on one of (i) a drilling tubular, and (ii) a wireline.
3
- 1 9. The method of claim 2 further comprising controlling a direction of drilling
2 using the estimated value of the property of the earth formation.
3
- 1 10. An apparatus configured to evaluate an earth formation the apparatus
2 comprising:
3 a tool having a body with a finite, non-zero conductivity configured to
4 be conveyed in a borehole;
5 a transmitter on the tool configured to produce a transient
6 electromagnetic signal in the earth formation;
7 at least one receiver configured to produce a signal responsive to
8 interaction of the transient signal with the earth formation, the signal
9 comprising a first time interval including a first component responsive to a
10 property of the earth formation and a second component responsive to the
11 conductivity of the tool, and a second time interval responsive substantially to
12 the conductivity of the tool; and
13 at least one processor configured to use the produced signal in the
14 second time interval and the produced signal in the first time interval to
15 estimate the first component of the signal in the first time interval.
16

- 1 11. The apparatus of claim 10 wherein the at least one processor is further
2 configured to use the estimated first component to estimate a value of the
3 property of the earth formation.
4
- 1 12. The method of claim 10, wherein the property of the earth formation is
2 selected from: (i) a resistivity property of the formation, and (ii) a distance to
3 an interface in the formation.
4
- 1 13. The apparatus of claim 10 wherein the at least one processor is further
2 configured to estimate the first component of the signal in the first time
3 interval by further:
4 (i) performing a least-squares fit to the second time interval of the
5 produced signal;
6 (ii) using fitting parameters derived in the least squares fit to define an
7 extrapolated signal in the first time interval; and
8 (iii) subtracting the extrapolated signal from the first signal.
9
- 1 14. The apparatus of claim 13 wherein the at least one processor is further
2 configured to perform the least-squares fit by further using an exponential
3 function.
4
- 1 15. The apparatus of claim 13 wherein the at least on processor is further
2 configured to perform the least-squares fit to signal in the second time interval
3 of the signal by further by further linearizing a fitting function about a nominal
4 value of a fitting parameter.
5
- 1 16. The apparatus of claim 15 wherein the at least one processor is further
2 configured to estimate the nominal value of the fitting parameter using a
3 calibration signal.
4
- 1 17. The apparatus of claim 10 further comprising a conveyance device configured
2 to convey the tool into the formation, the conveyance device being selected
3 from: (i) a drilling tubular, and (ii) a wireline.
4

- 1 18. The apparatus of claim 11 wherein the at least one processor is further
2 configured to control a direction of drilling based at least in part on the
3 determined value of the property of the earth formation.
4
- 1 19. A computer-readable medium product having stored thereon instructions that
2 when read by at least one processor cause the at least one processor to perform
3 a method, the method comprising:
4 processing a signal resulting from interaction of a transient
5 electromagnetic signal with the earth formation, the signal comprising a first
6 time interval including a first component responsive to a property of the earth
7 formation and a second component responsive to the conductivity of the tool,
8 and a second time interval responsive substantially to the conductivity of the
9 tool for estimating the first component of the signal in the first time interval.
10
- 1 20. The computer-readable medium of claim 19 further comprising at least one of:
2 (i) a ROM, (ii) an EPROM, (iii) an EEPROM, (iv) a flash memory, and (v) an
3 optical disk.
4

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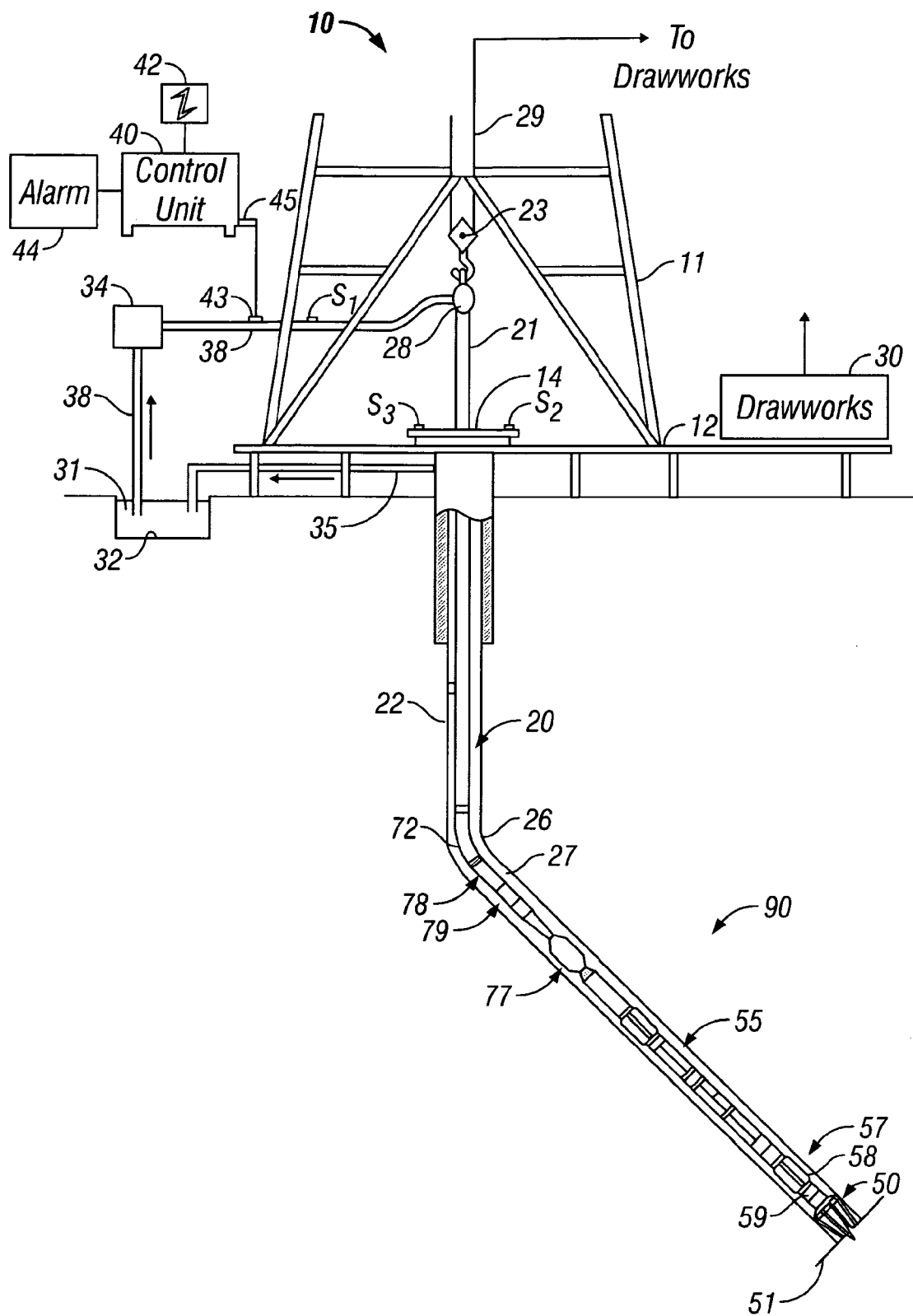


FIG. 1

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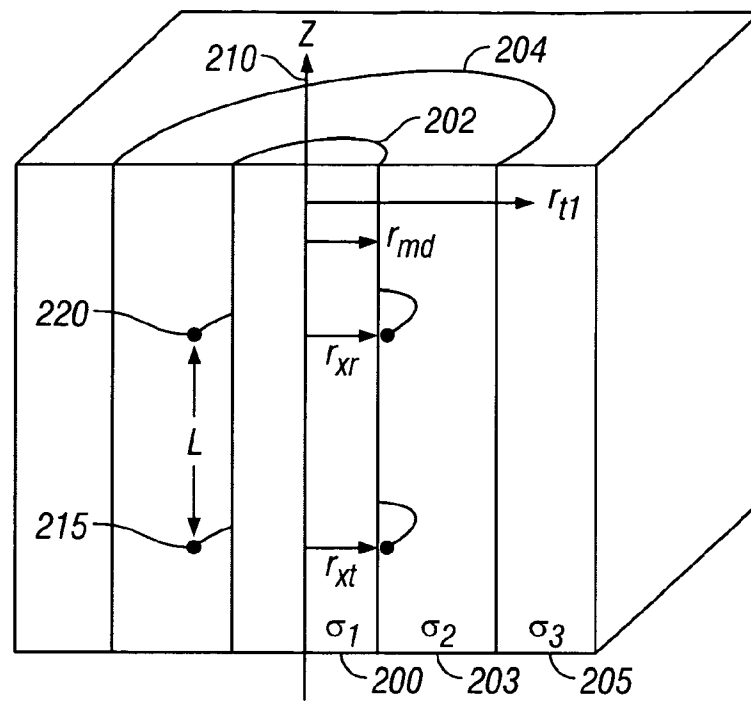


FIG. 2

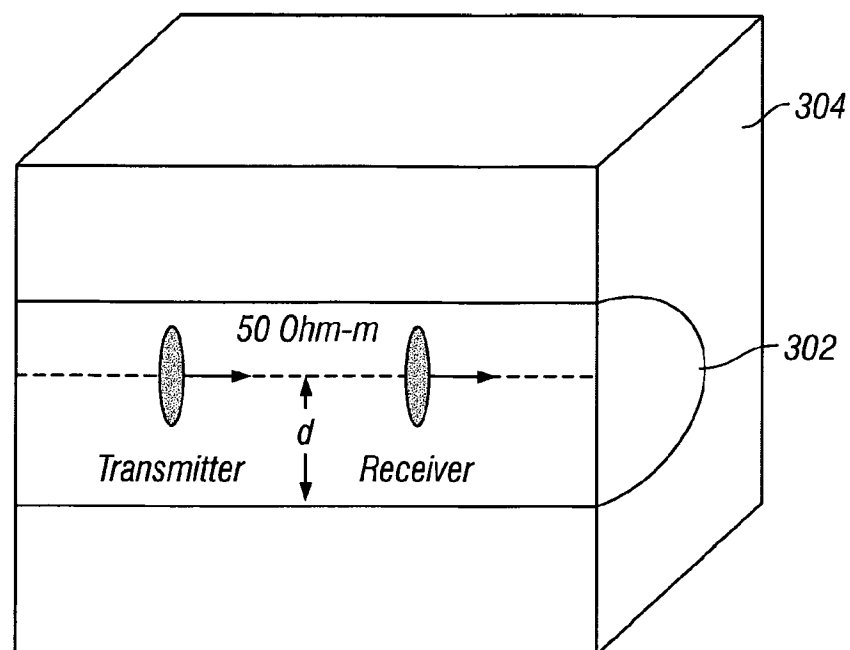


FIG. 3

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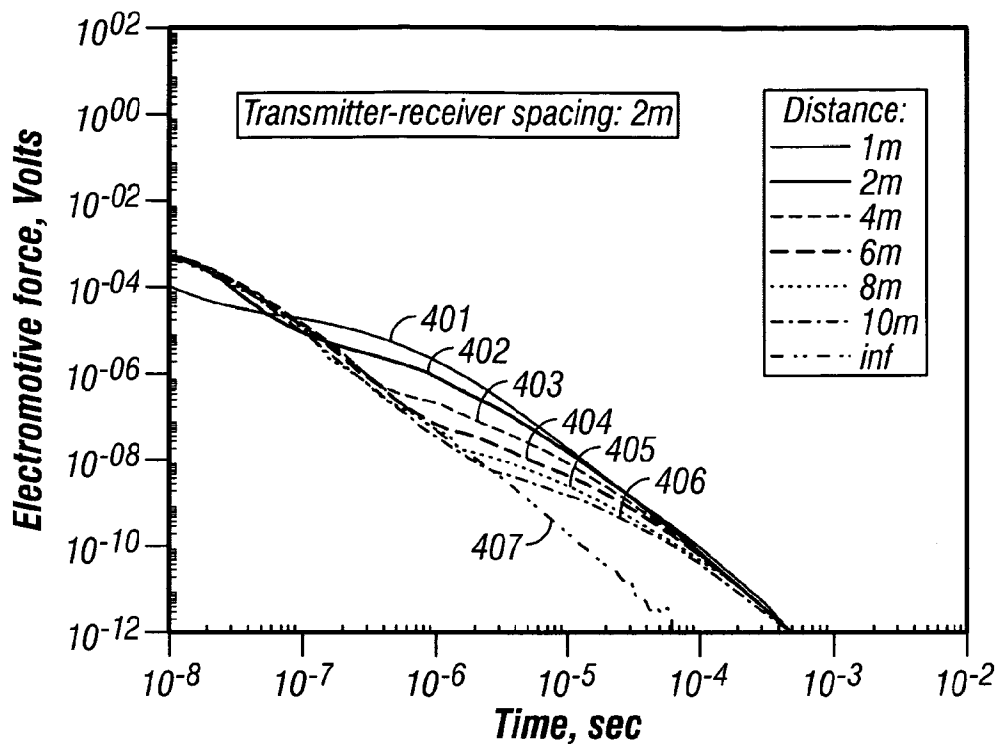


FIG. 4
(Prior Art)

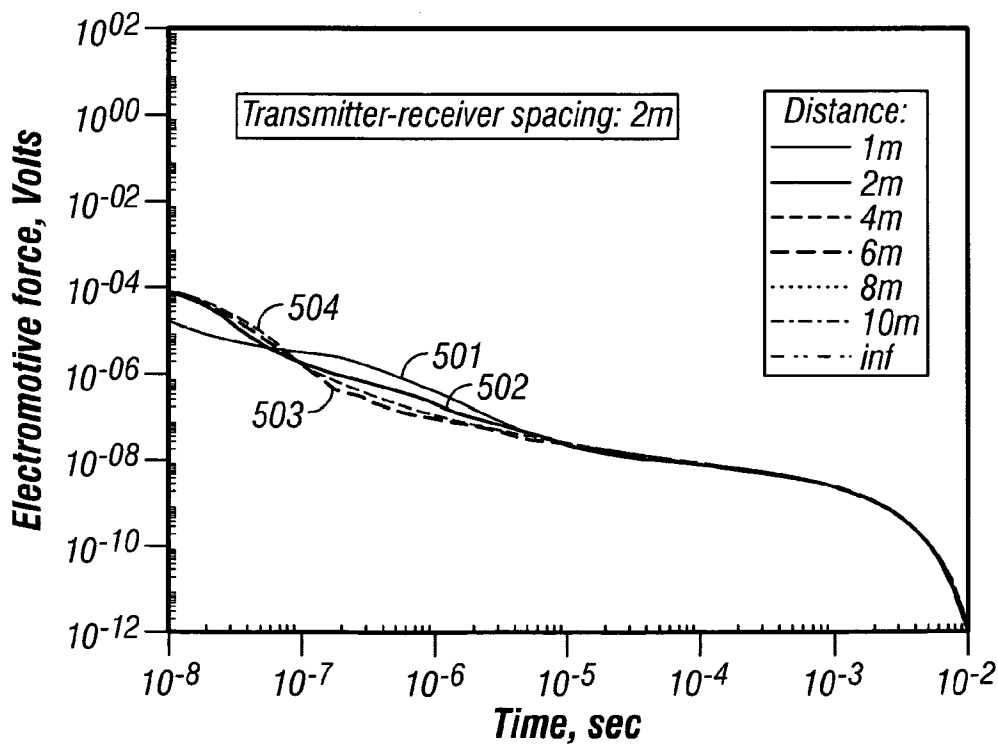


FIG. 5
(Prior Art)

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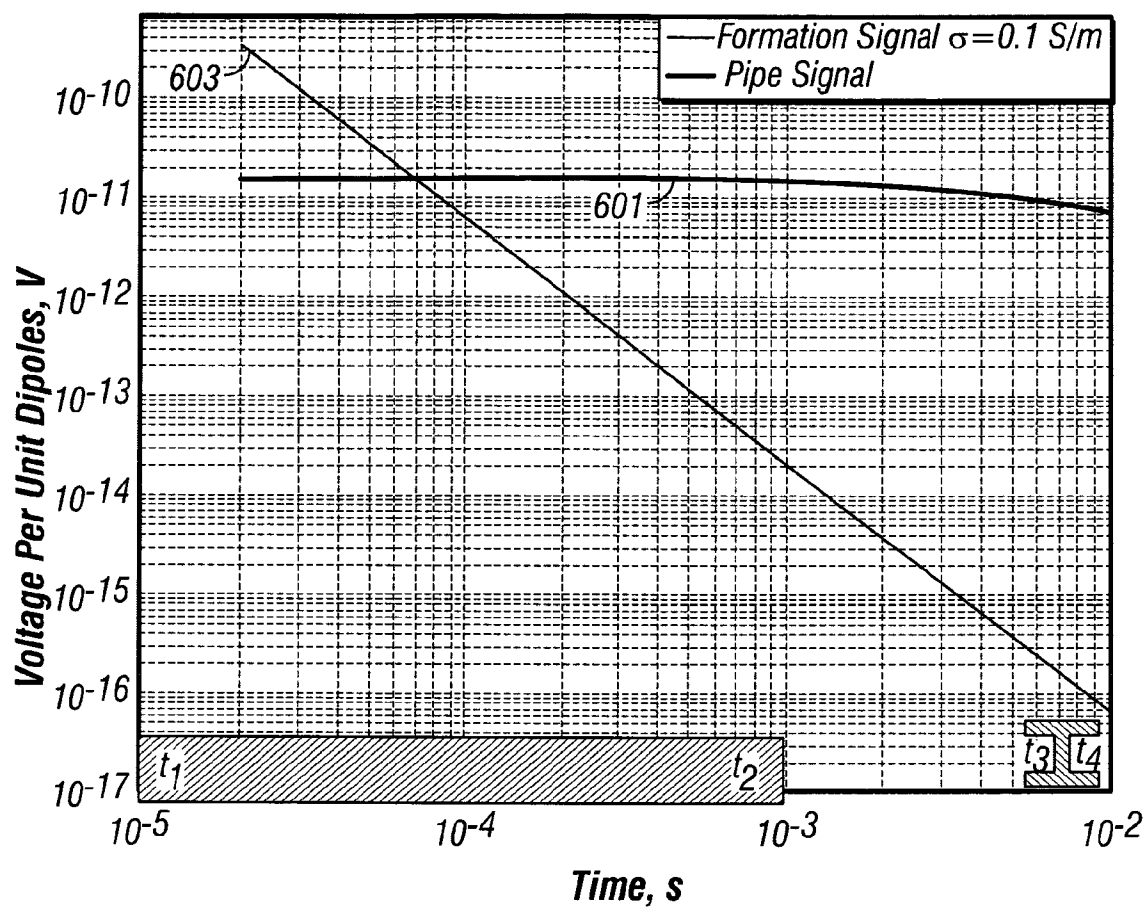


FIG. 6

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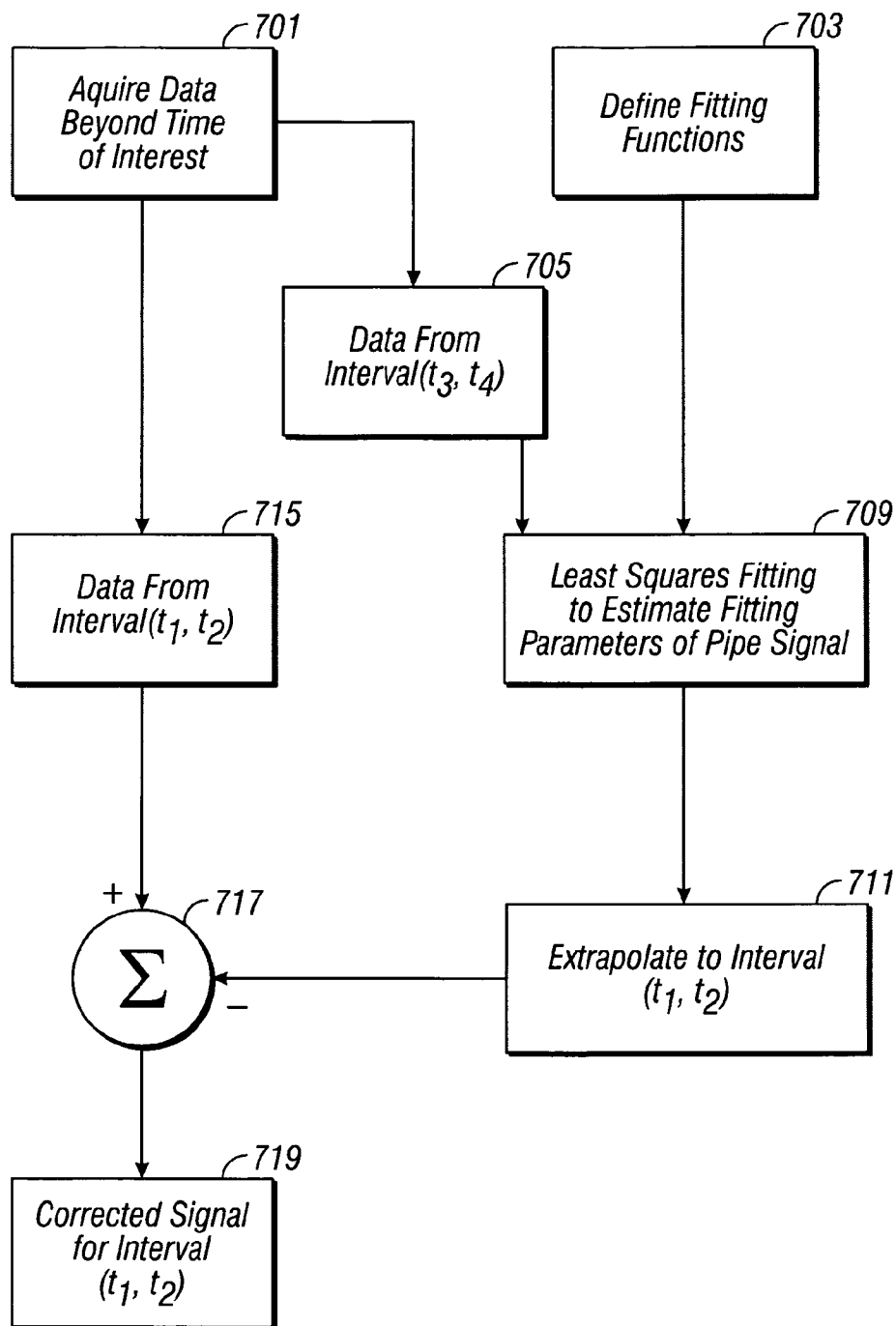


FIG. 7

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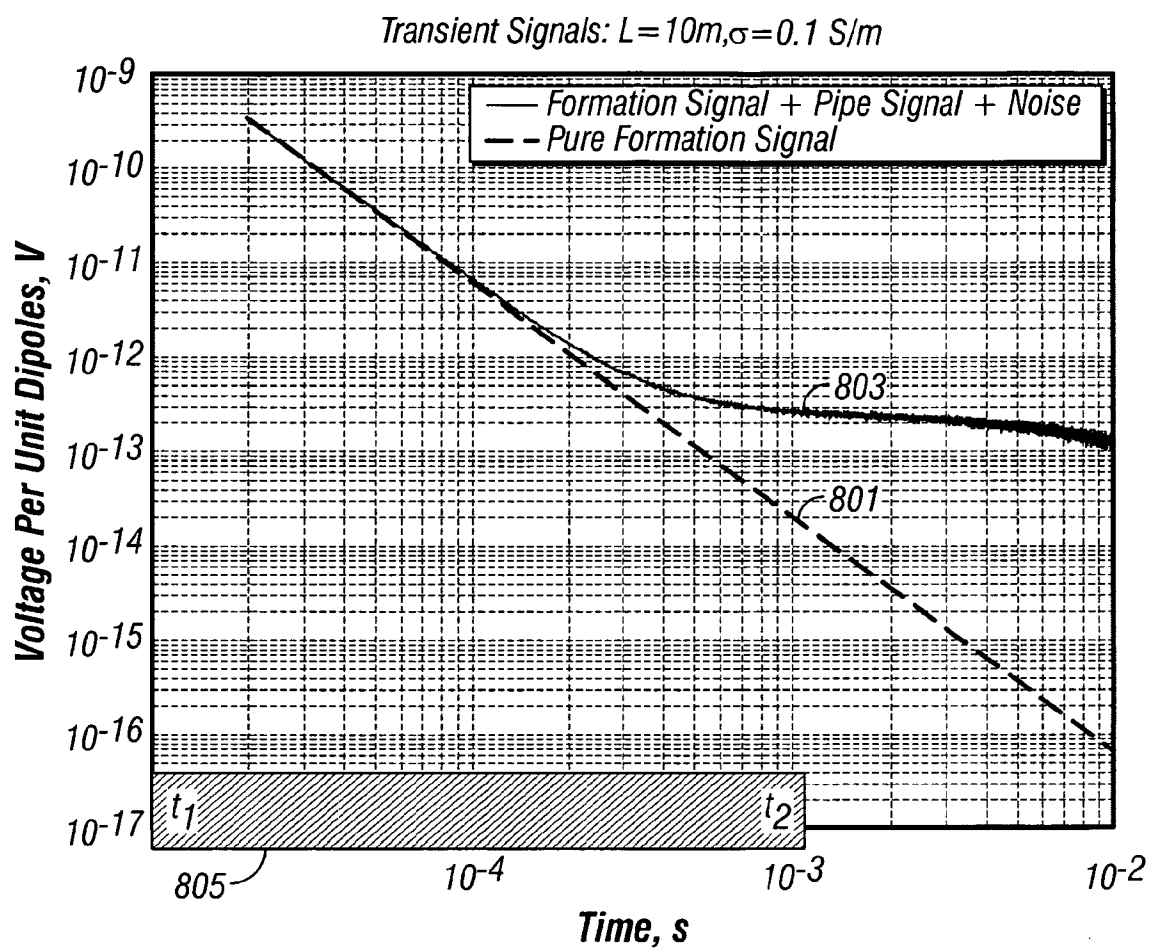
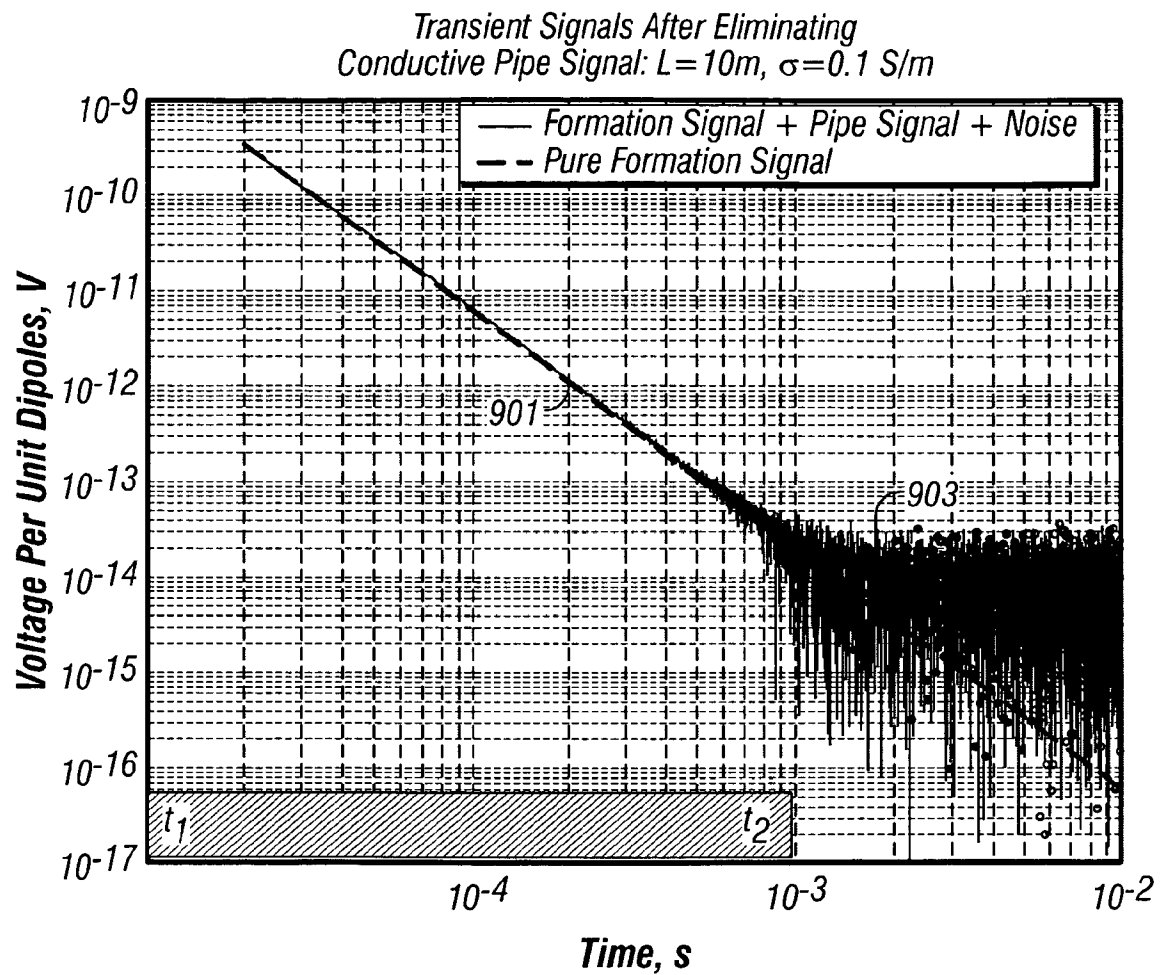


FIG. 8

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**FIG. 9**