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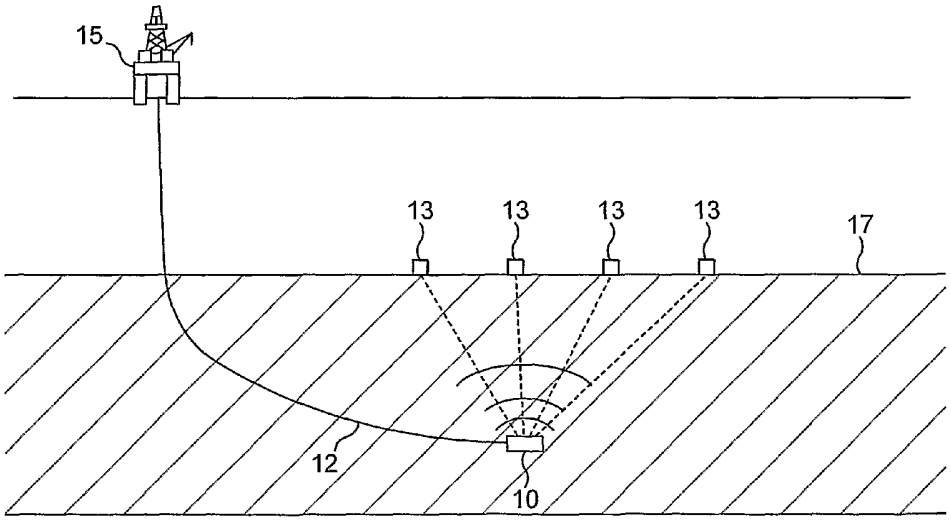
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(54) **Title:** SEISMIC DATA POSITIONING



(57) **Abstract:** A method of estimating the position of a subsurface drill bit (10) comprising the steps of a) obtaining seismic data relating to the traveltime between the drill bit (10) and at least two known locations (13) and b) calculating the position of the drill bit (10) relative to a model of the subsurface area, wherein only seismic data obtained in step a) is used to provide information on the drill bit's location. This method does not require magnetic or gyroscopic measurements to be taken. The seismic source/receiver can be associated with either the drill bit (10) or the known locations (13). Hyperbolic approximation or Bayesian Inversion can be used to calculate the drill bit's location.

WO 2006/106337 A1

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.

Seismic Data Positioning

This invention relates to the use of seismic data to calculate the position of a subterranean object, such as a drill bit.

When drilling an oil well it is very important to maintain an accurate estimate of the position of the drill. This is to ensure the target area (the reservoir zone) is hit and also to ensure that the drill avoids geological hazards.

First, seismic readings are taken to develop a seismic model of the geological area. This is used to locate the reservoir zone and decide the target boundaries, as well as to identify the surrounding rock strata and fault lines. As the traveltime of the seismic rays through each layer of rock is not known, the actual distance to the target is unknown. Thus, the depth axis of the seismic model is calibrated in terms of the time it takes a seismic ray to travel between points, not their spatial separation. The position of an object within the model is therefore given in 'two way time', i.e. the time taken for a seismic ray to travel from the surface to the object and back again.

In order to obtain spatial depths a velocity model must be used to convert the traveltimes shown in the seismic model into depth. The velocity model can be based on the velocity information inferred from seismic offset/ angle information or on the data obtained from nearby wells. This conversion allows the features shown in the seismic model to be located in geometrical space. Of course, errors and uncertainties in the velocity model translate into errors in the spatial positioning given by the geometric model. In addition, the seismic

model will itself contain errors. Therefore the position of the target area is not accurately known.

Once drilling starts the lateral position and depth of the drill bit are usually calculated using, for example, downhole magnetic and gyroscopic measurements and inertial navigation. By assuming these measurements give the true spatial position of the bit and by measuring the precise traveltime of seismic rays between the bit and a surface location, the velocity model can be updated to contain more accurate information on the speed of the seismic rays. The geometric location of the reservoir zone can therefore be more accurately predicted.

Several ways exist of obtaining the seismic traveltime. The most common method involves the use of a wireline tool. This requires the drill to be removed from the borehole and a wireline tool, which comprises a number of seismic receivers (known as geophones), to be inserted. A strong seismic signal, which can be picked up and easily identified by the wireline geophones, is then emitted from one or more sources at sea or ground level.

An advantage of this approach is that, in addition to being able to easily detect the direct seismic signal, reflections of the signal at the interface between strata below (i.e. ahead of) the drill bit can also be detected by the wireline tool. Detecting strata boundaries in this way is known as 'look ahead'. However, this method does have drawbacks. The need to remove the drill from the borehole makes this method lengthy, taking between several hours to a day to complete. The information cannot therefore be obtained in real time (i.e. processing and analysing data while drilling continues).

An alternative method which does allow at least some real time calculation involves placing geophones on the bottom hole assembly (BHA) near the drill bit. This system is described by Esmersoy et al in The Leading Edge, Jan 2005, p56-62. The geophones are arranged to detect signals from an above ground seismic source, e.g. seismic signals emitted from a vessel located above the drill bit (the location of which is known through downhole magnetic readings etc). The main drawback with this system is the fact that the data collected by the geophones cannot be transferred to the surface by means of an electrical cable as the harsh environment of the borehole and the drill string apparatus would quickly destroy any such cable. Current practice is therefore to use an acoustic mud pulse telemetry system. This however only allows for very slow data transmission (approximately 1 bit/s) and therefore only some of the data can be gained in real time. First arrival traveltime "picks" (initial waveform peaks) can be obtained in real time but the full waveform data must be stored in memory units until the BHA is brought to the surface. Therefore real time 'look ahead' is not currently possible when using this method.

Another possibility is to use the drill bit itself as the seismic source, with the seismic waves created by the drill being detected by geophones on the ground or sea floor (depending on whether drilling is taking place on or offshore). While this allows all the data to be collected in real time, identifying the drill signal is problematic. This is due to the comparatively weak signal sent by the drill bit in comparison with a standard seismic source. Further, unlike conventional seismic sources, which emit discrete, strong signals,

the drill bit signal is continuous and therefore it is not possible to know how long ago the received signal was generated. The received data must therefore be cross-correlated by looking for similar patterns at each receiver and working out the time difference between receipt of these patterns at the various receivers. This is done by defining a pilot trace (a selected and fixed trace from the data set) and determining the time difference between its detection at each geophone. During this process the absolute time reference is lost and must be restored during subsequent processing.

Methods for deciphering traveltime data from seismic readings are known in the art.

As noted above, once the seismic traveltime is known this can be combined with magnetic and other readings to provide an estimate of the location of the drill bit and geological features in a geometric model.

Obviously there are errors associated with each type measurement reading, brought about by environmental conditions and inaccuracies in the measurement apparatus.

Therefore, when steering the drill bit, the path of the drill must take into account the uncertainties in drill position as well as those associated with the target position. WO01/42621 discloses a method of assessing potential uncertainty in drilling a well which involves measuring of all of the above mentioned uncertainties.

According to one aspect, the present invention provides a method of estimating the position of a subsurface drill bit comprising the steps of

a) obtaining seismic data relating to the traveltime between the drill bit and at least two known locations; and

b) calculating the position of the drill bit relative to a model of the subsurface area;

wherein only the seismic data obtained in step a) is used to provide information on the drill bit's location.

As only one source of information is used, the system is less prone to malfunction. When three separate measurements are used (for example, seismic, magnetic and gyroscopic), all three measurement devices must be operating correctly to ensure an accurate estimate is made. However, by focussing solely on seismic readings an accurate estimate is not reliant on, for example, the gyroscope and magnetic readings.

The position of the drill bit can be calculated in respect to various different models of the subsurface area.

In one embodiment the drill bit position is calculated relative to a seismic model of the subsurface area.

This model contains details of the geological area, including the target area and the positions of various rock strata. While the seismic model does not contain any information regarding the actual physical depth of these elements, the inventors have realised that this is not necessary in order to guide the drill bit to the target area. As the target area and drill bit position can both be accurately positioned within the same seismic model, the drill bit can be guided to the target area without the need to calculate the physical depth of these objects.

However, it is preferred to know the spatial position of the drill bit and the geological features (e.g. the target area and strata layers) so that this information can be used when planning and drilling

further wells in the same area. Knowing the depth the wellbore must reach also provides the drill operator with useful information to help ensure the wellbore is correctly drilled and cased. Therefore in another embodiment the position of the drill bit is calculated relative to a geometric model. This model can either provide an actual spatial depth or a scaled depth, depending on what properties of the subsurface area are known.

In order to provide a position estimate within a geometric model a velocity model must be used. Preferably this velocity model is also applied to a seismic model of the subsurface area so that the geometric model can contain information not on only the drill bit position, but also on the position of various geological features such as the target area.

While only seismic data is used to provide information on the location of the drill bit, the present invention allows for other sources of information to be used when making various assumptions in the calculation. For example, in some embodiments information regarding the velocity model can be obtained from well survey data or from data from nearby wells.

However, preferably all additional data used in the model is obtained through seismic surveys. This provides a position estimate which is independent from the measurements gained, e.g. through magnetic and gyroscopic readings. By preventing the need for different measurements to be combined, gross errors in the readings are more likely to be noticed and prevented from influencing the final estimate.

Therefore, viewed from another aspect the present invention comprises a method of estimating the position of a subsurface drill bit comprising the step of

calculating the position of the drill bit relative to a model of the subsurface area using only seismic data.

Thus, it can be seen that the invention allows the position of the drill bit to be computed purely relative to the seismic model as well as allowing the drill bit position to be known in a geometric model built up purely through seismic measurements.

Viewed from another aspect the present invention provides a method of estimating the position of a subsurface drill bit in real time, the method comprising the steps of

a) obtaining seismic data relating to the traveltime between the drill bit and at least two known locations; and

b) calculating the position of the drill bit relative to a model of the subsurface area;

wherein no data used in the calculation, other than the seismic data of step a), is obtained during drilling.

Thus, all data regarding the model used in the calculation of step b), other than the seismic data relating to the position of the drill bit, is obtained prior to the commencement of drilling. Therefore, with only one measurement to be obtained, the calculation can be undertaken quickly and is limited in its dependence to the correct operation of the drilling equipment.

The seismic data of step a) will typically be obtained using at least one seismic source and at least one seismic receiver, one of said source and receiver being associated with the drill bit and the other being associated with the known locations.

By 'associated with' it is meant that the at least one source and receiver are located at or near the

associated object. This term also covers the situation where the source or receiver forms part of the object. For example, in one embodiment the drill may act as the seismic source, with the data being received at a plurality of receivers located at ground level.

Alternatively the seismic source is located above ground while the receiver is located on the BHA near the drill bit. In this instance a single seismic source can be operated from a plurality of known locations to provide the necessary traveltime data or a number of seismic sources can be stationed at particular known locations.

The position calculation may be made using a hyperbolic traveltime approximation or a hyperboloidic approximation in 3D applications. This provides a fast calculation and allows the position estimate to be made in real time.

Hyperbolic traveltime approximation is based on the NMO (Normal Move-Out) velocities from the surface seismics and the position of the known locations. The approximation works on the assumption that the seismic rays move in a straight line, i.e. the medium through which the rays passes is homogenous. It has been surprisingly found that this approximation can provide suitably accurate results for drill bit navigation in some situations.

When using a hyperbolic approximation step b) preferably comprises solving the equation

$$V_2^2[d_k^2 - d_j^2 + 2(f_C - \varepsilon_T)(d_k - d_j)] = x_k^2 - x_j^2 - 2(x_k - x_j)x_0 + y_k^2 - y_j^2 - 2(y_k - y_j)y_0 + [z_k^2 - z_j^2 - 2(z_k - z_j)z_0](1 + 2\delta) \quad (1)$$

where V_2 is the NMO velocity (i.e. $\frac{1}{V_{NMO}^2} = \frac{dT^2}{dx^2}\Big|_{x=0}$), (x_0, y_0, z_0) is the unknown subsurface position of the drill bit, (x_k, y_k, z_k) and (x_j, y_j, z_j) are the positions of known locations k and j respectively, d_k and d_j are the seismic measurements between the drill bit and surface stations k and j respectively, $f_C = 0$ when the receivers are associated with the drill bit and $f_C = T_0$ (the zero offset traveltime) when the source is associated with the drill bit, ε_T is the systematic time picking error and δ is one of the Thompsen parameters. These parameters are known in the art (see Thompsen, L., 1986 Weak elastic anisotropy. Geophysics 51 1954-1966).

In order to solve this equation two scenarios can be considered. First, in the case when $z_k \neq z_j$, i.e. at least one of the surface stations is at depth (z_j) different from the depth (z_k) of the other stations (or station). Then equation (1) can be written as a 6 x (N − 1) linear system of equations

$$\mathbf{Am} = \mathbf{b}, \tag{2}$$

where row k of matrix A is given by

$$\mathbf{A}=[2(x_k-x_j)\ \ 2(y_k-y_j)\ \ 2(z_k-z_j)\ \ -2(z_k^2-z_j^2)\ \ 2(d_k-d_j)\ \ (d_k^2 - d_j^2)] \tag{3}$$

and

$$\mathbf{b} = [(x_k^2- x_j^2) + (y_k^2-y_j^2) + (z_k^2-z_j^2)] \tag{4}$$

and

$$m=[x_0\ \ y_0\ \ \tilde{z}_0\ \ \delta\ \ \kappa\ \ \lambda]^T \tag{5}$$

where

$$\tilde{z}_0 = (1+2\delta)z_0 \tag{6}$$

$$\kappa = V_2^2(f_C - \varepsilon_T) \tag{7}$$

$$\lambda = V_2^2 \tag{8}$$

In the matrix **A**, the first 4 columns are obtained from navigation data only (i.e. the positions of subsurface stations d_k and d_j), and columns 5 and 6 from traveltime measurements. Hence, when $z_k \neq z_j$ the subsurface position (x_0, y_0, z_0), the seismic parameters V_2 and δ and the quantity $f_C - \varepsilon_T$ associated with vertical traveltime and systematic picking error can be computed using only seismic measurements.

Therefore, simply using seismic data together with prior knowledge of the positions of the known locations (i.e. surface stations) can provide the user with a wealth of information regarding the drill bit position and the velocity model. The quantities fc and ε_T can not be resolved separately due to column degeneracy. The linear system has redundancy if $N > 7$.

Secondly, in the case when $z_k = z_j$ (i.e. all surface stations are at the same depth), then,

$$\mathbf{A} = [2(x_k - x_j)\ \ 2(y_k - y_j)\ \ 2(d_k - d_j)\ \ (d_k^2 - d_j^2)], \quad (9)$$

$$\mathbf{b} = [(x_k^2 - x_j^2) + (y_k^2 - y_j^2)], \quad (10)$$

$$\mathbf{m} = [x_0\ y_0\ \kappa\ \lambda]^T \quad (11)$$

In this case, equation (2) does not contain information about z_0 and δ. However, the scaled depth, $\tilde{z}_0$, can be calculated from

$$\tilde{z}_0 = z_0\sqrt{1+2\delta}, \quad (12)$$

from

$$Q_k = (z_k - z_0)\sqrt{1+2\delta}, \quad (13)$$

where

$$Q_k^2 = V_2^2[d_k + (f_C - \varepsilon_T)]^2 - (x_k - x_0)^2 - (y_k - y_0)^2, \quad (14)$$

Equation (14) is known after the solution of equation (1). Hence, when all the surface stations have the same depth, z_0 and δ can not be resolved separately. Therefore the position of the drill bit is known only in relation to a geometric model using scaled depth. To obtain the true vertical depth z_0, the anisotropy parameter δ must be known *apriori*.

In each case equation (1) may be solved by singular-value decomposition (SVD) or by many other known mathematical methods.

Although in some situations the hyperbolic approximation (which assumes a homogeneous medium) provides a suitably accurate estimation, it may be too imprecise for many applications where a more complex velocity model is required.

Therefore, alternatively, the position estimate of the drill bit can be obtained using Bayesian Inversion. Here, the variables of interest, i.e. the drill bit and velocity parameters, are assigned *a priori* probability distributions and the seismic traveltime data obtained in step a) of the invention is linked to these variables by a forward operating model. This model contains the geophysical equation, which can be the hyperbolic traveltime equation or another equation of choice.

This method has the advantage that uncertainty can be incorporated in a systematic way and also allows a more complex velocity model to be used, e.g. to take account of strata with varying slownesses.

In order to limit the complexity of the calculation and therefore reduce the calculation time, it is preferable to create a model which allows for an inhomogeneous velocity model, but which restricts the velocity perturbations to an overall scaling of the

velocity field. This can be achieved using the velocity model

$$V + \Delta V = \frac{V}{1+\nu} \qquad (15)$$

where V is a prior velocity value and ν is a perturbation parameter inferred from analysis.

While hyperbolic approximation and Bayesian Inversion have been named as potential means by which a position estimate can be obtained, many other mathematical methods could also be employed for this purpose. The invention is not limited to the use of any specific mathematical process or processes.

Once a position estimate has been obtained, this information can be used to predict one or more later positions of the drill bit. In this way the entire well path can be estimated and assumptions regarding a smooth well path and a slowly varying velocity model can be included to increase the accuracy of the prediction.

Preferably therefore the method further includes the step c) of predicting the future position of the drill bit based on successive drill bit position estimates.

The successive drill bit locations along the well path can be assigned a prior probability distribution which penalises abrupt changes in the well path, and which imposes a fairly constant speed of drilling. For example, this may include the distance between data acquisition points, which is typically one stand (30m), or it may be that a well is drilled vertically, indicating a small change in the lateral coordinates of a well. Of course, the probability distributions may be fitted according to the specific application at hand. This also goes for the associated uncertainty of the prior information.

One option for modelling this prior information about the variables is by a Markov (one-step) type of probability distribution.

$$[m(t) \mid m(t-1)] = N[A[m(t-1)], Q] \quad (16)$$

Where $N(\mu, Q)$ denotes a Gaussian probability distribution with mean μ and covariance matrix Q, and where $A(m)$ is a nonlinear function imposing the prior information on the well and velocity variables with m defining the variables of interest. The time index $t = 1, \ldots, T$ are the points where data are acquired. When using this probability distribution it is also possible to use a linear function A. The choice of function will depend on which parameterisations of the variables are implemented by the user.

Step c) does not require the input of any additional measurements regarding the position of the drill bit and therefore the method still only requires the gathering of seismic data during the operation of the drill. It is however possible, if desired, to include additional measurements, for example in order to perform a quality control check. However, in order to benefit from the main advantages of the present invention it is preferable not to include additional data obtained from sources other than the seismic data obtained in step a).

Viewed from another aspect, therefore, the invention provides a method of predicting the future position of a subsurface drill bit based on successive drill bit position estimates, wherein the position prediction is obtained using only seismic traveltime data.

A Kalman filter can be used to carry out this method step as it can provide a good linear estimate of

the variables in a Bayesian Markov model conditioned on the data. This can be used to provide a position prediction based on previously estimated positions as well as smoothed estimates, in which later measurements are also incorporated.

As well as allowing the position of the drill bit to be estimated, seismic rays can also be used to 'look ahead' of the bit. Rays sent out from a seismic source reflect off interfaces in rock strata (known as reflectors) and are detected by the receiver. These signals can be used to calculate how far the drill bit is from the reflector and can also give information on the reflector's orientation. Preferably therefore, step a) further comprises obtaining seismic data relating to the traveltime of rays reflected from a reflector and step b) further comprises predicting the position of the reflector relative to the model.

Again, this calculation can incorporate additional information on the drill bit's position but this is undesirable as it increases the number of factors on which the method is dependent. The reflectors can be located in either the seismic model or the geometric model in the same way as the drill bit.

In addition, measuring direct rays and look-ahead rays gives several special cases. In the simple calculations above only the direct ray traveltimes were considered. Therefore the drill bit was positioned relative to the positions of the known locations. It is also possible just to use the look-ahead traveltimes to provide a position estimate. In this case the model gives the position the drill-bit relative to a reflector (possibly the target). The third case would be to use both the direct and look-ahead traveltime measurements, as illustrated in the specific embodiment below.

Therefore the model can contain only information regarding the drill bit and the reflector, showing the relative positions of these two objects, or the model can include information on the positions of these objects relative to the known locations also.

Viewed from another aspect the present invention provides a method of estimating the position of a reflector positioned ahead of a subsurface drill bit wherein the prediction is obtained using only seismic traveltime data.

As mentioned previously, it is important to know the accuracy of the position estimates being obtained so that the drill operator knows how much credence can be placed on the estimate. Therefore, it is preferable for the method to include calculating the error associated with each position estimate obtained. As also discussed previously, the Bayesian inversion method provides one means of automatically including the error margin within the position calculation. Any other probabalistic formulation would also achieve this.

The method can preferably be used in conjunction with other methods of estimating the position of the drill bit, such as gyroscopic and magnetic based methods. Having two independent position estimates with associated error margins gives the operator more information and allows him to compare two separate position estimates, together with their error margins, and gain a better picture of the drill position. Therefore it is easier for the final (combined) uncertainty to be controlled.

The method of the present invention can also be used 'in reverse' to assist in the planning of a drilling operation. Before acquiring seismic borehole data it is valuable to study what can be gained by dense

placing of surface sources /geophones or having a large offset for these sources / receivers. This can be done by designing several model configurations and then using the method of the present invention to obtain a drill bit position estimate for each one. The accuracy of the resulting estimates can be evaluated to determine the most suitable configuration to use during drilling.

Such studies are very important prior to real-time applications where the data transfer capacity is very limited. Hence, if the same accuracy can be achieved with half the data, there is no reason for collecting the full set. It is also important for the cost evaluation of data acquisition. Therefore, using the method of the present invention with synthetic or previously acquired data, position estimates relating to a number of different configurations of known locations can be acquired and the most suitable configuration can be chosen before drilling begins. The most suitable configuration will be chosen by the drilling operator based on a balance between the accuracy of the position estimate and the cost and logistical limitations present.

Therefore viewed from another aspect the present invention provides a method of determining the number of known locations necessary to provide a position estimate of a pre-determined accuracy, comprising repeatedly carrying out the method of any of the previously mentioned aspects of the invention to calculate the subsurface position of a drill bit using synthetic and/or real seismic data in step a), wherein the number and position of the known locations are adjusted through trial and error until the pre-determined accuracy is obtained.

Preferred embodiments of the present invention shall now be described, by way of example only, with reference to the accompanying drawings, in which:

FIG 1 shows a method of collecting seismic data in which the receiver is associated with the drill bit;

FIG 2 shows an alternative method of collecting seismic data in which the source is associated with the drill bit;

FIG 3 shows a well path with T unknown locations and a surface aperture of L sources/receivers; and

FIG 4 shows a drill bit and a surface source/receiver together with a look ahead ray reflected of a dipping reflector.

In FIG 1, drill bit 10 is located at the bottom of borehole 12 and is operated from oil rig 15. The bottom hole assembly (BHA) contains a seismic receiver to detect seismic signals in the vicinity of the drill bit 10. Seismic signals are sent out from seismic source 14, which is transported to various locations by vessel 16. The co-ordinates of these locations are known and can therefore be used in later calculations. The data collected by the receiver is sent to the oil rig 15 through borehole 12 via a mud pulse telemetry system. This system has a low band width and therefore only the first arrival traveltime picks can be obtained in real-time. However, the remaining data in stored in memory units and can accessed when the drill bit 10 is brought back to the surface. The data contained in these units can then be used for creating a smoothed estimate as well as providing 'look ahead' information.

FIG 2 shows an alternative means of collecting seismic data. Here, drill bit 10 acts as the seismic source, with the seismic waves it creates during

drilling being detected by an array of geophones placed on the sea floor. Although the deciphering of these signals is more complex due to the weak continuous signal supplied by the drill bit 10, the entire seismic waveform can be obtained in real time.

In both the FIG 1 and FIG 2 arrangements Bayesian Inversion is used to estimate the position of the drill bit in a geological model. This allows the incorporation of a inhomogeneous velocity model (i.e. one which allows layered or griddled velocities) which is not possible with the hyperbolic approximation discussed previously.

Using Bayesian Inversion theory, the forward modelling operator is taken to be

$$F_k(m) = T_k(m,\theta) - \varphi \qquad (17)$$

where $\varphi = f_C - \varepsilon_T$ and T_k is the traveltime from well position x_0 to surface location x_k.

This operator contains the physics of the problem and predicts synthetic data from model parameters m. A noise term n takes care of any physics not modelled for by $F(m)$.

Here the components of θ are deterministic parameters while m is a vector of the qualities it is desired to estimate. These vectors can then be chosen as

$$m = [x_0 \quad V_2 \quad \varphi \quad \ldots]^T \text{ and} \qquad (18)$$

$$\theta = [x_k \quad V_0 \quad \delta \quad \ldots]^T , \qquad (19)$$

where $V_0 = \frac{z_k - z_0}{T_0}$

although parameters can be included or excluded from the inverse problem by transfer between these vectors.

Linearised operator G can be written as

$$\frac{\partial F(\mu_m)}{\partial m} \qquad (20)$$

where μ_m is a linearisation point and therefore using the above m vector G becomes

$$G = \begin{bmatrix} p_0 & \frac{\partial T}{\partial V_2} & -1 & \dots \end{bmatrix} \qquad (21)$$

where $p_0 = \nabla_0 T$ is the slowness vector at well position $\mathbf{x}_0$ and ∇_0 denotes the differentiation with respect to $\mathbf{x}_0$. For an inhomogeneous velocity model, p_0 is the slowness computed in the prior velocity model. An inhomogeneous interval velocity model has a large number of degrees of freedom, which would increase the time taken to calculate the subsurface position to an inappropriate amount.

Therefore, it is preferable to restrict the velocity perturbations to an overall scaling of the velocity field

$$V + \Delta V = \frac{V}{1+\nu} \qquad (22)$$

where V is a prior velocity value and ν is a perturbation parameter.

If the velocity perturbation is small $\nu << 1$, it can be assumed that the ray paths are unchanged. It is then possible to obtain

$$T(\nu) = \int_{ray} \frac{(1+\nu)}{V} dl = (1+\nu)T(0) \qquad (23)$$

and the derivative with respect to the velocity field can be replaced by the simple expression

$$\frac{\partial T(\nu)}{\partial \nu} = T(\nu = 0) \qquad (24)$$

where $\nu=0$ in the prior model. Then vectors m, θ and G can be rewritten as

$$m = \begin{bmatrix} x_0 & \nu & \varphi \end{bmatrix}^T \qquad (25)$$

$$\theta = \begin{bmatrix} x_k & V_0 & \delta & \dots \end{bmatrix}^T \quad (26)$$

$$G = \begin{bmatrix} p_0 & T & -1 \end{bmatrix} \quad (27)$$

It can easily be verified that these equations are also valid in the hyperbolic approximation.

FIG 3 shows the sketch of a well path 22 and a given survey aperture. The unknown position of the drill bit at reference time t is denoted by $[x(t), y(t), z(t)]$, where $[x(t), y(t)]$ are the lateral coordinates and $z(t)$ is depth. The reference time t represents the times when seismic traveltimes are conducted, and T denotes the total number of such acquisition times. Hence at each t seismic rays 24 are sent between the source(s) and receiver(s) and seismic traveltimes are obtained. By assuming there are L receivers/sources 20 at fixed surface locations $(x_l, y_l, z_l); l = 1, \dots, L$ the collection of traveltimes at time t is then $d(t) = [d_1(t), \dots, d_L(t)]'$. The mean velocity at time t is parameterised as

$$v(t) = \frac{V}{1 + \nu(t)} \quad (28)$$

for a fixed prior value V and an unknown perturbation $\nu(t)$.

The well location at time point t is predicted from the well locations at time $t-1$ and $t-2$ in the following manner

$$\begin{aligned} x(t) &= x(t-1) + [x(t-1) - x(t-2)] + \lambda_1(t) \\ y(t) &= y(t-1) + [y(t-1) - y(t-2)] + \lambda_2(t) \\ z(t) &= z(t-1) + [z(t-1) - z(t-2)] + \lambda_3(t) \\ \nu(t) &= \nu(t-1) + \lambda_4(t) \end{aligned} \quad (29)$$

for $t = 2, \dots, T$. where $\lambda(t) = [\lambda_1(t), \dots, \lambda_4(t)]' \sim N(0, Q_1)$ for all t, and where Q_1 is a fixed 4×4 positive definite

matrix. With the variables of interest written in augmented form $m(t)=[x(t),y(t),z(t),x(t-1),y(t-1),z(t-1),v(t)]'$ the Markov prediction in equation (29) can be rewritten as

$$[m(t)\,|\,m(t-1)]\sim N[Am(t-1),Q] \qquad (30)$$

Note that this equation is equivalent to equation (16) except that here the forward model A is linear and is defined as

$$A=\begin{bmatrix} 2 & 0 & 0 & -1 & 0 & 0 & 0 \\ 0 & 2 & 0 & 0 & -1 & 0 & 0 \\ 0 & 0 & 2 & 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 \end{bmatrix}$$

If different parameterisations were being used then the non linear version of the Markov model shown in equation (16) could be used.

As an initial guess of the model variables at time $t=1$ m(1) is set as

$$[m(1)]=[x(1),y(1),z(1),x(0),y(0),z(0),v(1)]'\sim N(m_0,Q_0). \qquad (31)$$

for fixed values of mean m_0 and covariance matrix Q_0. The Markov model in equation (30) entails dependency between the well locations. In a Bayesian framework equation (30) and (31) define the prior model and summarize assumptions that are made about the model variables prior to acquiring the data .

Note that, as mentioned above, alternative Markov models are possible, for example the information provided by the length of each stand in the well could be used. But in this way the well and the seismic traveltime data are coupled in the estimation procedure, and it might not be very robust in a quality control perspective.

The traveltimes $\{d_l(t)\colon l=1,\ldots,L;t=1,\ldots,T\}$ can be calculated from the location of source(s) and

receiver(s) using the medium velocity in equation (28). The traveltimes are set as

$$d_l(t) = \frac{[1+v(t)]}{V}\sqrt{(x(t)-x_l)^2+(y(t)-y_l)^2+(z(t)-z_l)^2} + D_0 + \varepsilon_l(t), l = 1,\ldots,L, t = 1,\ldots,T. \quad (32)$$

where the first part of this equation is the traveltime from source to receiver in a one layer / isotopic medium. Further, D_0 is a possible shift in the traveltime and $\varepsilon(t) = [\varepsilon_1(t),\ldots,\varepsilon_L(t)]' \sim N(0,R_1)$ is a noise term that accounts for the possible shortcomings of the geological model. More complicated geophysical links are of interest in this step. The parameterization has to depend on the quality and amount of data, however. In some data acquisition methods, for example wireline obtained seismic data, it may be desired to accommodate direct measurements of the well location using drilling data. These data are in addition to the seismic traveltimes and can be incorporated by setting

$$[d_{L+1}(t), d_{L+2}(t)]' = [x(t), y(t), z(t)]' + [\varepsilon_{L+1}(t), \varepsilon_{L+2}(t)]' \quad (33)$$

where $[\varepsilon_{L+1}(t), \varepsilon_{L+2}(t)]' \sim N(0,R_2)$ is a measurement error term. In quality control cases it is not desirable to include these measurements at this point of the estimation scheme since it might be better to find position estimate using only seismic data, and then do a final quality check based on the drilling data. In the method of the present invention therefore the covariance R_2 is set to very large values so that the drilling measurements carry no information about the drill bit position.

Equation (32) and (33) relate the unknown position and velocity variables to the observations. In a Bayesian model this defines the likelihood of the data $d(t) = [d_1(t),\ldots, d_L(t), d_{L+1}(t), d_{L+2}(t)]'$ conditional on the

variables of interest $m(t)$. In short form this becomes

$$[d(t)|m(t)] \sim N\{b[m(t);\theta],R\}, t=1,...,T, \quad (34)$$

where $b[m(t);\theta]$ is a combined function denoting both the non-linear relationships in equation (32) and the linear relationship in equation (33), with θ containing the fixed parameters V , x_1, y_1 , $z_1,...,x_L,y_L,z_L$, D_0 and where R is a block diagonal matrix of size $(L+2)\times(L+2)$ with R_1 and R_2 on the block diagonal.

The Kalman filter provides a recipe for constructing the best linear estimate of the variables in a Bayesian Markov model conditioned on the data. Output from the method is a linear approximation to the conditional expectation and the conditional covariance. In the model above this means that the position / velocity estimates and position / velocity covariances, respectively are obtained. The expectation and covariance describe the entire probability density function (pdf) in the Gaussian case.

As mentioned above, the fixed position of L source(s) or receiver(s) on the surface are denoted by (x_l,y_l,z_l): $l=1,...,L.$. Unknown positions along the well path are denoted $x(1),y(1),z(1),...,x(T),y(T),z(T)$ where, T is the number of acquisition times for the seismic data. It is also desirable to estimate not only the drill bit location 40, but also the location of the first reflector below the drill bit 42, see FIG 4. This can be achieved according to the present invention using only seismic data to provide information on the drill bit and reflector locations. According to a preferred embodiment this is achieved by adapting the velocity model to

$$v(t)=\frac{V}{[1+\nu(t)]},\quad u(t)=\frac{V}{[1+\xi(t)]},\quad t=1,\ldots,T, \tag{35}$$

where $v(t)$ is the mean velocity at time t for the direct seismic ray 43 and $u(t)$ is the mean velocity at time t for the look ahead seismic ray 44. Both $\nu(t)$ and $\xi(t)$ are unknown, while V is fixed from a priori knowledge. It is assumed that the interface below the drill bit is a dipping interface with a constant dip. The dipping interface is parameterised with the unknown depth at location $(x,y)=(0,0)$, denoted δ, the unknown dip in the x direction denoted γ, and the unknown dip in the y direction denoted ζ. In the estimation procedure these unknown parameters are predicted on-line along wit the drill bit position and they hence get a time index t in the following.

An augmented state vector of all unknown variables is defined as

$$m(t)=[x(t),y(t),z(t),x(t-1),y(t-1),z(t-1),\nu(t),\xi(t),\delta(t),\gamma(t),\zeta(t)]'$$

To relate variables at time t to those at time $t-1$ the Markov model of equation (30) is employed in which matrix A is given by

$$A=\begin{bmatrix} 2 & 0 & 0 & -1 & 0 & 0 & 0_{1\times5} \\ 0 & 2 & 0 & 0 & -1 & 0 & 0_{1\times5} \\ 0 & 0 & 2 & 0 & 0 & -1 & 0_{1\times5} \\ 0 & 0 & 0 & 1 & 0 & 0 & 0_{1\times5} \\ 0 & 0 & 0 & 0 & 1 & 0 & 0_{1\times5} \\ 0 & 0 & 0 & 0 & 0 & 1 & 0_{1\times5} \\ 0_{5\times1} & 0_{5\times1} & 0_{5\times1} & 0_{5\times1} & 0_{5\times1} & 0_{5\times1} & I_{5\times5} \end{bmatrix}$$

where $0_{k\times l}$ indicates a $k\times l$ matrix of zeros, $I_{k\times k}$ is the size k identity matrix.

As an initial guess of the model variables at time $t=1$ m(1) is set to

$$[m(1)]=[x(1),y(1),z(1),x(0),y(0),z(0),v(1),\xi(1),\delta(1),\gamma(t),\zeta(1)]' \sim N(m_0,Q_0). \quad (36)$$

for fixed values of mean m_0 and covariance matrix Q_0. Possible extensions of equation (30) are possible, for example that the velocity parameters $\xi(t)$ and $v(t)$ are coupled in some way, or a more complicated velocity model in general. Equation (30) and (36) together define the a priori assumptions about the variables.

Next, a likelihood link between the unknown variables and the observed seismic traveltimes is derived. The direct ray calculation was discussed above and it is

$$d_l(t)=\frac{[1+v(t)]}{V}\sqrt{(x(t)-x_l)^2+(y(t)-y_l)^2+(z(t)-z_l)^2} + D_0+\varepsilon_l(t), l=1,\ldots,L, t=1,\ldots,T, \quad (37)$$

where $\varepsilon_1(t)=[\varepsilon(1),\ldots,\varepsilon_L(t)]' \sim N(0,R_1)$ is a noise term, and where D_0 is a possible shift in the traveltimes. The look ahead calculation becomes more sophisticated. It is based on first finding the reflection point at the dipping interface for a ray going from/to $[x(t),y(t),z(t)]'$ to/from $(x_l,y_l,z_l)'$. Denote by $c(t,l)=\sqrt{(x(t)-x_l)^2+(y(t)-y_l)^2+(z(t)-z_l)^2}/2$ the half distance between the source and receiver. Let further $r=(r_x,r_y,r_z)'$ be the reflection point at the dipping interface. In a constant velocity medium (straight rays), (r_x,r_y,r_z) equals the point where an ellipsoid 45 with distance $c(t,l)$ to the foci and foci at $[x(t),y(t),x(t)]'$ and $(x_l,y_l,z_l)'$ has a tangent that is equal to the plane defined by $\gamma(t)$, $\delta(t)$ and $\zeta(t)$. If the model is studied in the x,z plane and the origin set equal to the midpoint between $[x(t),y(t),z(t)]'$ and $(x_l,y_l,z_l)'$, the point of reflection is given by

$$r_x = \frac{-\delta(t)\gamma(t)}{\gamma(t)^2 + \frac{g^2}{c(t,l)^2+g^2}} \quad (38)$$

$$r_z = \delta(t) + \gamma(t) r_x \quad (39)$$

where

$$g = \sqrt{\frac{\delta(t)^2 - \gamma(t)^2 c(t,l)^2}{1+\gamma(t)^2}} \quad (40)$$

is the minor semi axis of this ellipsoid. Such reflection ellipsoids also characterize all possible reflection points for a fixed velocity and they have been used for that purpose in the prior art. The seismic traveltime for a look ahead ray is then given by

$$\begin{aligned} d_{L+l}(t) = \frac{[1+\xi(t)]}{V}[&\sqrt{(x(t)-r_x)^2+(y(t)-r_y)^2+(z(t)-r_z)^2} \\ &+\sqrt{(r_x-x_l)^2+(r_y-y_l)^2+(r_z-z_l)^2}] \\ &+E_0+\varepsilon_{L+l}(t), l=1,\ldots,L, t=1,\ldots,T. \end{aligned} \quad (41)$$

where $\varepsilon_2(t) = [\varepsilon(L+1),\ldots,\varepsilon_{2L}(t)]' \sim N(0,R_2)$ is a noise term, and where E_0 is a possible shifts in the traveltimes. Typically the direct ray is much easier to pick from a seismic section than the look ahead ray and the variance elements in R_1 should be smaller than those in R_2.

If the position by drilling equipment is also measured we have

$$[d_{2L+1}(t), d_{2L+2}(t)]' = [x(t), y(t), z(t)]' + [\varepsilon_{2L+1}(t), \varepsilon_{2L+2}(t)]' \quad (42)$$

where $[\varepsilon_{2L+1}(t), \varepsilon_{2L+2}(t)]' \sim N(0,R_3)$ is a measurement error term.

Equations (37), (41) and (42) define the likelihood terms that link the variables to the data. In short form we can write

$$[d(t)\,|\,m(t)] = [d_1(t),\ldots,d_{2L+2}(t)\,|\,m(t)] \sim N\{b[m(t);\theta],R\}, t=1,\ldots,T, \quad (43)$$

where $b[m(t);\theta]$ is a complicated non-linear function of $m(t)$ which imposes prior information on the well and

velocity variables. Recall that (r_x, r_y, r_z) are non-linear functions of $m(t)$, and this is a part of the b function too. The fixed parameters θ contain V, x_l, z_l, $l=1,...,L$, and R is the covariance matrix made up of R_1, R_2 and R_3 on the block diagonal.

In summary, the Bayesian formulation previously described ([m(t)|m(t-1)]) and the likelihood equation ([d(t)|m(t)]) define a probability distribution for the variables m conditional on the data d. One may analyse this distribution recursively in real-time using a Kalman filter or other method. This requires the calculation of the derivatives of non linear functions A and b. With the simple hyperbolic traveltime equation and the look-ahead calculation presented above, the derivatives can be obtained analytically. When using a more complex geophysical equation, this calculation can be done numerically.

Therefore, using the method of the present invention, a wide range of useful information can be obtained when only seismic data is used to provide information on the location of the drill bit. The use of a single measurement source reduces the errors involved. Further, the method can preferably be used in conjunction with other methods of estimating the position of the drill, such as gyroscopic and magnetic based methods.

Claims:

1. A method of estimating the position of a subsurface drill bit comprising the steps of

a) obtaining seismic data relating to the traveltime between the drill bit and at least two known locations; and

b) calculating the position of the drill bit relative to a model of the subsurface area;

wherein only the seismic data obtained in step a), is used to provide information on the drill bit's location.

2. A method as claimed in claim 1 wherein the model comprises a seismic model of the subsurface area.

3. A method as claimed in claim 1 wherein the model comprises a geometric model.

4. A method as claimed in claim 3 wherein the method further comprises

converting geological features shown in the seismic model into the geometric model.

5. A method as claimed in claim 3 or 4 wherein step b) comprises using a hyperbolic approximation.

6. A method as claimed in claim 5 wherein step b) comprises solving the equation

$$V_2^2[d_k^2 - d_j^2 + 2(f_C - \varepsilon_T)(d_k - d_j)] = x_k^2 - x_j^2 - 2(x_k - x_j)x_0 + y_k^2 - y_j^2 - 2(y_k - y_j)y_0 + [z_k^2 - z_j^2 - 2(z_k - z_j)z_0](1 + 2\delta)$$

where V_2 is the NMO velocity, (x_0, y_0, z_0) is the unknown subsurface position of the drill bit, (x_k, y_k, z_k) and (k_j, y_j, z_j) are the positions of known locations k and j respectively, d_k and d_j are the seismic measurements for known locations k and j respectively, $f_C = 0$ when at least one seismic receiver is associated with the drill bit and $f_C = T_0$ (the zero offset traveltime) when at least one seismic source is associated with the drill bit, ε_T is the systematic time picking error and δ is one of the Thompsen parameters.

7. A method as claimed in claim 6 wherein the equation is written as a 6 x (N-1) linear system of equations

$$\mathbf{Am} = \mathbf{b}$$

wherein

$$\mathbf{A} = [\ 2(x_k - x_j)\ \ 2(y_k - y_j)\ \ 2(z_k - z_j)\ \ -2(z_k^2 - z_j^2)\ \ 2(d_k - d_j)\ \ (d_k^2 - d_j^2)\ ]$$

$$\mathbf{b} = [(x_k^2 - x_j^2) + (y_k^2 - y_j^2) + (z_k^2 - z_j^2)]$$

and

$$m = [x_0 \ \ y_0 \ \ \breve{z}_0 \ \ \delta \ \ \kappa \ \ \lambda]^T$$

where

$$\breve{z}_0 = (1 + 2\delta)z_0$$
$$\kappa = V_2^2(f_C - \varepsilon_T)$$
$$\lambda = V_2^2$$

8. A method as claimed in claim 6 wherein the equation is written as a 6 x (N-1) linear system of equations

$$\mathbf{Am} = \mathbf{b}$$

where

$\mathbf{A} = [2(x_k-x_j)\ \ 2(y_k-y_j)\ \ 2\{d_k-d_j)\ \ (d_k^2-d_j^2)]$,

$\mathbf{b} = [(x_k^2-x_j^2) + (y_k^2-y_j^2)]$,

and

$\mathbf{m} = [x_0\ y_0\ \kappa\ \lambda]^T$

where

$$\kappa = V_2^2(f_C - \varepsilon_T)$$
$$\lambda = V_2^2$$

9. A method as claimed in claim 8 wherein the scaled depth, $\tilde{z}_0$ is given by

$$\tilde{z}_0 = z_0\sqrt{1+2\delta},$$

which can be calculated from

$$Q_k = (z_k - z_0)\sqrt{1+2\delta},$$

where

$$Q_k^2 = V_2^2[d_k + (f_C - \varepsilon_T)]^2 - (x_k - x_0)^2 - (y_k - y_0)^2$$

10. A method as claimed in claim 7, 8 or 9 wherein the equation is solved using singular value decomposition.

11. A method as claimed in claim 3 or 4 wherein step b) comprises using Bayesian inversion to calculate the drill bit's position.

12. A method as claimed in claim 11 when dependent upon claim 4, wherein the velocity model used in the Bayesian inversion is used to convert the geological features into the geometric model.

13. A method as claimed in claim 11 or 12, wherein a velocity model is used which restricts the velocity perturbations to an overall scaling of the velocity field.

14. A method as claimed in any preceding claim, wherein the method further comprises;

predicting the future position of the drill bit based on successive drill bit position estimates

15. A method as claimed in any preceding claim, further comprising calculating the error margin associated with the position estimate of the drill bit in the model.

16. A method as claimed in any preceding claim wherein step a) further comprises obtaining seismic data relating to the traveltime of rays reflected from a reflector and step b) further comprises estimating the position of the reflector relative to the model.

17. A method as claimed in claim 16, further comprising calculating the error margin associated with the position estimate of the reflector in the model.

18. A method as claimed in any preceding claim, wherein the seismic data of step a) is obtained using at least one seismic source and at least one seismic receiver, one of said source and receiver being associated with the drill bit and the other being associated with at least one of the known locations.

19. A method as claimed in claim 18, wherein the at least one seismic source is associated with a known above ground location and the at least one seismic receiver is associated with the drill bit.

20. A method as claimed claim 18, wherein the at least one seismic source comprises the drill bit and a plurality of seismic sources are associated with known above ground locations.

21. A method as claimed in any preceding claim, wherein the method further comprises the step of using the position estimate in conjunction with a position estimate obtained using a different method.

22. A method of estimating the position of a subsurface drill bit in real time, the method comprising the steps of

a) obtaining seismic data relating to the traveltime between the drill bit and at least two known locations; and

b) calculating the position of the drill bit relative to a geological model of the subsurface area;

wherein no data used in the calculation, other than the seismic data of step a), is obtained during drilling.

23. A method as claimed in claim 22 wherein the model comprises a seismic model of the subsurface area.

24. A method as claimed in claim 23 wherein the model comprises a geometric model.

25. A method as claimed in claim 24 wherein the method further comprises

converting geological features shown in the seismic model into the geometric model.

26. A method of determining the number of known locations necessary to provide a position estimate with a pre-determined error margin, comprising

repeatedly carrying out the method of any preceding claim to calculate the subsurface position of a drill bit using synthetic and/or real seismic data in step a), wherein the number and position of the known locations are adjusted through trial and error until the pre-determined error margin is obtained.

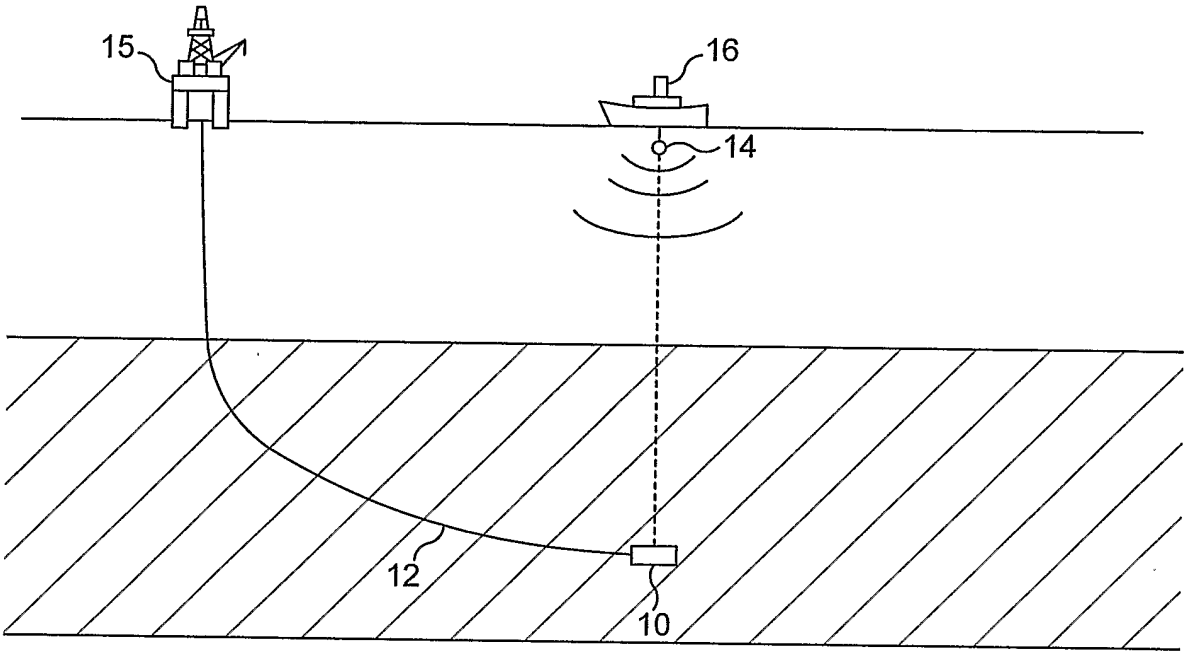


FIG. 1

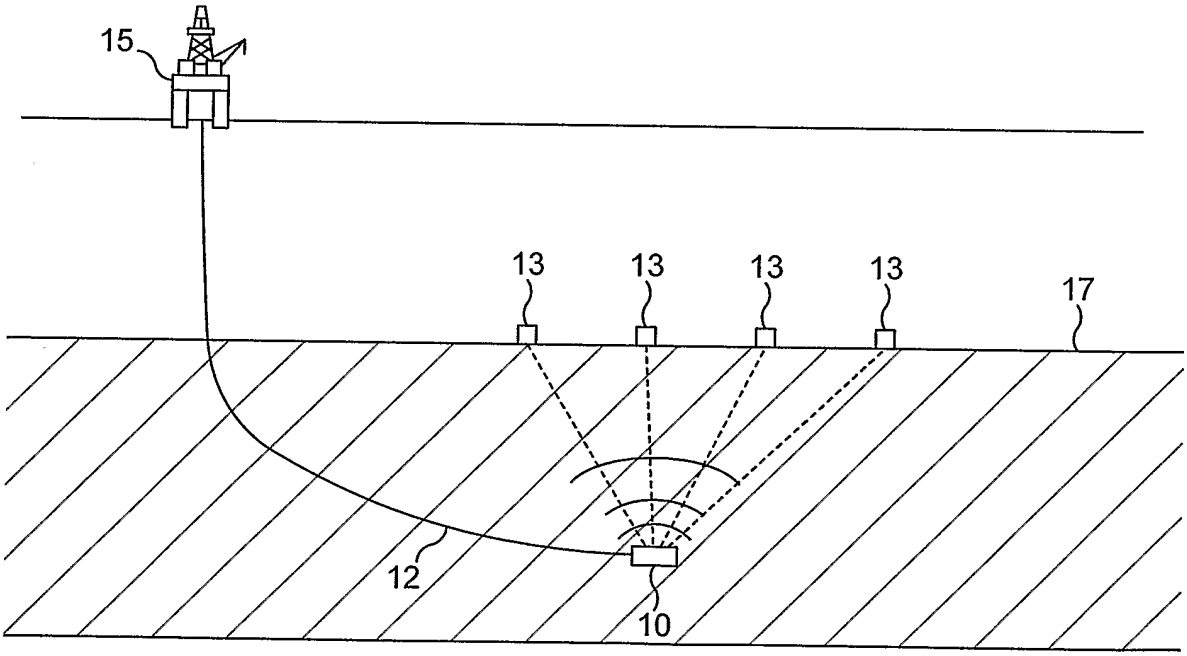


FIG. 2

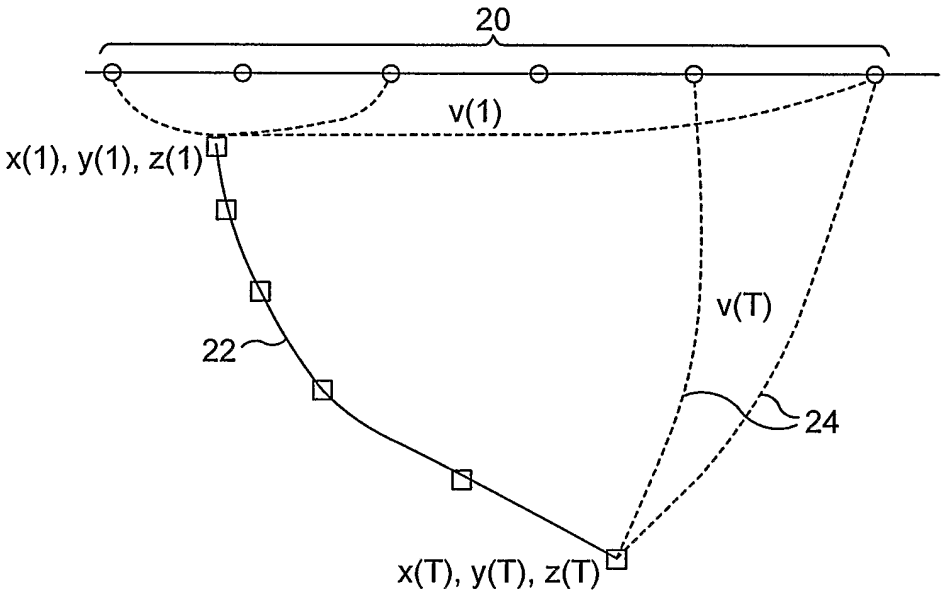

20
v(1)
x(1), y(1), z(1)
v(T)
22
24
x(T), y(T), z(T)

FIG. 3

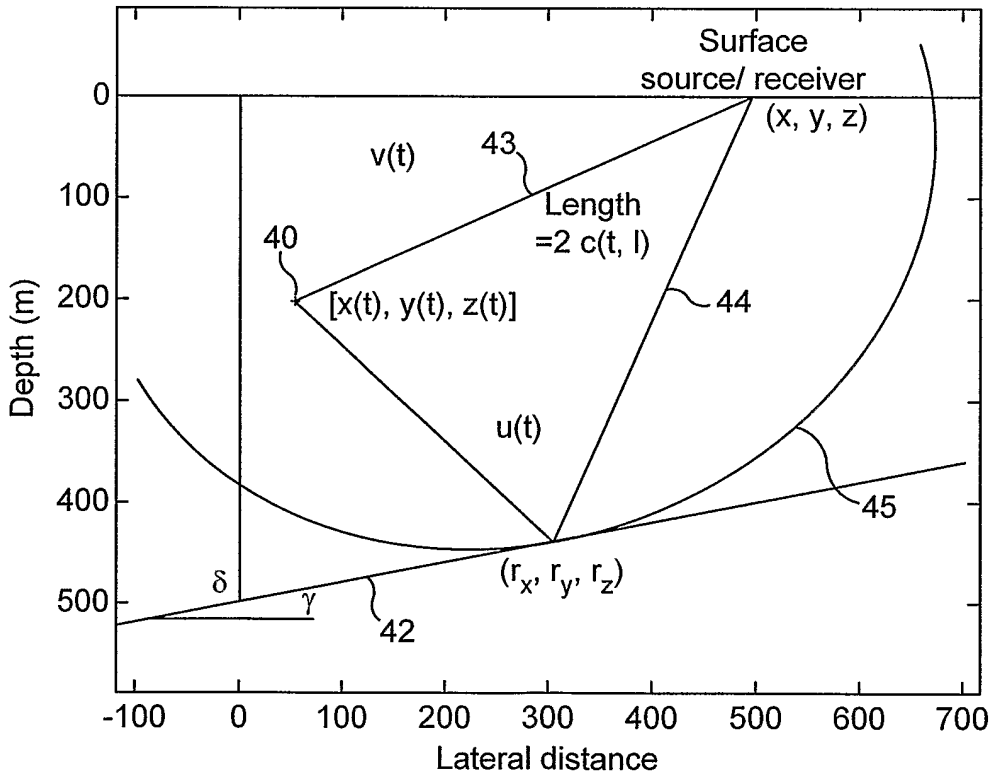

Surface
source/ receiver
(x, y, z)
v(t)
43
Length
=2 c(t, l)
40
[x(t), y(t), z(t)]
44
u(t)
45
δ
γ
42
(r_x, r_y, r_z)
Depth (m)
0
100
200
300
400
500
-100
0
100
200
300
400
500
600
700
Lateral distance

FIG. 4

INTERNATIONAL SEARCH REPORT

International application No
PCT/GB2006/001259

A. CLASSIFICATION OF SUBJECT MATTER
INV. G01V1/42

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
G01V

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

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)
EPO-Internal, WPI Data, INSPEC, COMPENDEX

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2003/137899 A1 (HJORTH JAN ET AL) 24 July 2003 (2003-07-24) paragraphs [0001], [0004], [0010], [0012]; claim 1	1,22,26
X	US 2004/047234 A1 (ARMSTRONG PHILIP ET AL) 11 March 2004 (2004-03-11) paragraphs [0016], [0055] - [0064]; claim 1	1,22,26
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A	US 5 995 446 A (MEYER ET AL) 30 November 1999 (1999-11-30) claim 1	1,22,26

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[X] Further documents are listed in the continuation of Box C.

[X] See patent family annex.

* Special categories of cited documents :

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"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

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

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
10 July 2006	14/07/2006

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INTERNATIONAL SEARCH REPORT

International application No
PCT/GB2006/001259

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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