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[Continued on next page]

(54) Title: QUALITY CONTROL FOR USE WITH SEISMIC SURVEYS

(57) Abstract: Seismic data that had been acquired from a group of seismic sensors disposed on a plurality of seismic streamers is received. Low-frequency noise in the seismic data is estimated. An orientation angle error of at least one of the seismic sensors in the group of seismic sensors is estimated based on the low-frequency noise in the seismic data. The seismic data is analyzed based on the estimated orientation angle error. An acquisition of the seismic data is managed based on the analysis.

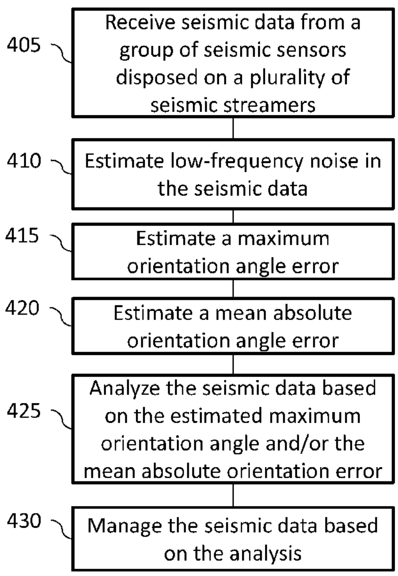

Figure 4

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QUALITY CONTROL FOR USE WITH SEISMIC SURVEYS

BACKGROUND

[0001] In some scenarios, seismic exploration has been performed in two areas, namely marine and on land. On land, numerous seismic sensors can be placed on/in the ground, a source can be provided, and the reverberations can be sensed by the sensors, recorded, and from this images and information relating to the subsurface can be generated thus showing the presence, or lack thereof, of various minerals such as hydrocarbons and/or water.

[0002] In marine surveys, streamers can be towed by boats. These streamers can be quite long and often are up to 8-12 km long and are made up of numerous sections connected to one another. It is possible to tow 8-12 of these streamers side-by-side to one another. There are seismic sensors connected along the streamers at various spacing. The source projects an impulse that travels though the water and into the subsurface of the seafloor. The impulse reflects and reverberates and is detected and recorded by the sensors in the streamers. The data that is sensed / recorded can then be processed and analyzed to produce images and information about the subsurface and the presence, or lack thereof, of various minerals such as hydrocarbons and/or water.

[0003] Improvement in the hardware and processes for marine surveys may increase the quality of acquired seismic data. One such improvement may relate to the capabilities of the sensors. Another may relate to the efficiency and accuracy of the surveys.

[0004] In contrast to land surveys, marine surveys may be limited by the number of streamers that can be towed by each vessel. In land surveys, more and more land sensors can be used (only being limited by cost and availability essentially), the land sensors can be spaced much more closely to one another, to improve the survey. However, in marine surveys there may be a limited number of streamers that can be towed by each vessel due to drag and limited power of the vessels. Also, the closer streamers are to one another, the larger the chance of entanglements. Thus, seismic surveys may be configured to tow both a wide spread (distance between the two outermost streamers), with a large number of streamers so that there is a short distance laterally between the streamers that is feasible and safe.

[0005] A challenge for the industry is to produce good data while having a wide overall spread and a low feasible distance between the streamers in the lateral direction.

[0006] One way to address these issues is by interpolating (thus generating/reconstructing) data between streamers, where streamers are not present, that would have been detected between the streamers if a sensor / streamer was present. In such a scenario, various steps of preconditioning processing of the initial data that is detected by the streamers can be done and can provide improvements in the survey.

[0007] Various techniques for quality control and/or the like may be used when generating and/or reconstructing the data between the streamers.

SUMMARY

[0008] Described herein are implementations of various technologies for providing quality control for use with seismic surveys. Seismic data that had been acquired from a group of seismic sensors disposed on a plurality of seismic streamers is received. Low-frequency noise in the seismic data is estimated. An orientation angle error of at least one of the seismic sensors in the group of seismic sensors is estimated based on the low-frequency noise in the seismic data. The seismic data is analyzed based on the estimated orientation angle error. An acquisition of the seismic data is managed based on the analysis.

[0009] In one implementation, the seismic data may be analyzed and managed in real time during a seismic survey. Managing the acquisition may include stopping a seismic survey, continuing the seismic survey or reacquiring the seismic survey based on the analysis. In another implementation, the seismic data may be analyzed and managed after acquisition.

[0010] The estimated orientation angle error may be at least one of an estimated maximum orientation angle error and a mean absolute orientation error. Estimating low-frequency noise in the seismic data may include: computing low-pass filtered data by applying a high cut filter in the time domain to the seismic data; computing a squared two-norm of the low-pass filtered data; estimating a mean of the squared two-norm; and estimating an average noise level based on at least the estimated mean. The mean absolute orientation angle error may be determined by substituting the estimated average noise level for the amplitude of the noise. The maximum orientation angle error may be determined by substituting the estimated average noise level for the amplitude of the noise.

[0011] Described herein are implementations of various technologies for providing quality control for use with seismic surveys. Seismic data that had been acquired from a group of seismic sensors disposed on a plurality of seismic streamers is received. A twist rate along a length of at least one of the plurality of seismic streamers is estimated based on the seismic data. An accumulated number of twists along the length is estimated. A determination is made as to whether the accumulated number of twists exceeds a threshold. Based on the threshold a determination is made as to whether the at least one of the plurality of seismic streamers is to be replaced or untwisted.

[0012] Estimating the twist rate may include computing low-pass filtered data by applying a high cut filter in the time domain to the seismic data.

[0013] In one implementation, estimating the twist rate may include: determining a gradient in space of the low-pass filtered data; and using the low-pass filtered data and the gradient to estimate the twist rate.

[0014] In another implementation, estimating the twist rate may include: determining an orientation angle of the at least one seismic sensor; performing phase unwrapping of the orientation angle; and computing the twist rate by differentiating the orientation angle in space. The orientation angle may be determined by computing an arctangent of the low-pass filtered data. Phase unwrapping may be performed by removing 2π phase jumps from the orientation angle.

[0015] Described herein are implementations of various technologies for providing quality control for use with seismic surveys. Seismic data that had been acquired from a group of seismic sensors disposed on a plurality of seismic streamers is received. At least two physical properties of the plurality of seismic streamers is estimated using the acquired seismic data and transversal vibration noise found in the seismic streamers.

[0016] Estimating the at least two physical properties may include: computing a Fourier transform of the seismic data; performing an frequency-wavenumber domain analysis to identify a plurality of pairs of natural frequencies and wavenumbers that lie on a model of transverse vibration noise as peaks of the Fourier transform; and setting a linear system of equations with the at least two physical properties as unknowns.

[0017] In one implementation, tension is known and the at least two physical properties are bending stiffness and density. The at least two physical properties, e.g., bending stiffness and density, may be determined by using least-squares inversion.

[0018] In another implementation, density is known and the at least two physical properties are tension and bending stiffness. The at least two physical properties, e.g., tension and bending stiffness, may be determined by using least-squares inversion.

[0019] The computing systems, methods, processing procedures, techniques and workflows disclosed herein are directed to methods for performing quality control for use with seismic surveys.

[0020] In another implementation, a computing system may include at least one processor, at least one memory, and one or more programs stored in the at least one memory, where the programs include instructions, which when executed by the at least one processor, are configured to perform any method disclosed herein.

[0021] In yet another implementation, a computer readable storage medium may have stored therein one or more programs, the one or more programs including instructions, which when executed by a processor, cause the processor to perform any method disclosed herein.

[0022] In yet another implementation, a computing system may include at least one processor, at least one memory, and one or more programs stored in the at least one memory, and means for performing any method disclosed herein.

[0023] In yet another implementation, an information processing apparatus for use in a computing system may include means for performing any method disclosed herein.

[0024] These systems, methods, processing procedures, techniques, and workflows increase effectiveness and efficiency. Such systems, methods, processing procedures, techniques, and workflows may complement or replace conventional methods for performing quality control for use with seismic surveys.

[0025] The above referenced summary section is provided to introduce a selection of concepts in a simplified form that are further described below in the detailed description section. The summary is not intended to identify key features or essential features of the claimed subject matter, nor is it intended to be used to limit the scope of the claimed subject matter. Furthermore, the claimed subject matter is not limited to implementations that solve any or all disadvantages noted in any part of this disclosure.

BRIEF DESCRIPTION OF THE DRAWINGS

[0026] Implementations of various techniques will hereafter be described with reference to the accompanying drawings. It should be understood, however, that the accompanying drawings illustrate the various implementations described herein and are not meant to limit the scope of various techniques described herein.

[0027] Figure 1 illustrates a schematic diagram of a marine-based seismic acquisition system in accordance with implementations of various techniques described herein.

[0028] Figure 2 illustrates a frequency-wavenumber spectra in accordance with implementations of various techniques described herein.

[0029] Figure 3 illustrates a plot of cable twists in accordance with implementations of various techniques described herein.

[0030] Figure 4 illustrates a flow diagram of a method for rotation quality control in accordance with implementations of various techniques described herein.

[0031] Figure 5 illustrates a flow diagram of a method for twist quality control in accordance with implementations of various techniques described herein.

[0032] Figure 6 illustrates a flow diagram of a method for estimation of physical properties from seismic data in accordance with implementations of various techniques described herein.

[0033] Figure 7 illustrates a schematic diagram of a computing system in accordance with implementations of various techniques described herein.

DESCRIPTION

[0034] Reference will now be made in detail to implementations, examples of which are illustrated in the accompanying drawings and figures. In the following description, numerous specific details are set forth in order to provide a thorough understanding of the implementations. However, it will be apparent to one of ordinary skill in the art that the implementations may be practiced without these specific details. In other instances, well-known methods, procedures, components, circuits and networks have not been described in detail so as not to unnecessarily obscure aspects of the implementations.

[0035] It will also be understood that, although the terms first, second, etc., may be used herein to describe various elements, these elements should not be limited by these terms. These terms are used to distinguish one element from another. For example, a first object could be termed a second object, and, similarly, a second object could be termed a first object, without departing from the scope of the implementations. The first object, and the second object, are both objects, respectively, but they are not to be considered the same object.

[0036] The terminology used in the description of the implementations herein is for the purpose of describing particular implementations and is not intended to be limiting. As used in the description and the appended claims, the singular forms “a,” “an” and “the” are intended to include the plural forms as well, unless the context clearly indicates otherwise. It will also be understood that the term "and/or" as used herein refers to and encompasses any possible combinations of one or more of the associated listed items. It will be further understood that the terms "includes," "including," "comprises" and/or "comprising," when used in this specification, specify the presence of stated features, integers, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, operations, elements, components, and/or groups thereof.

[0037] As used herein, the term "if" may be construed to mean "when" or "upon" or "in response to determining" or "in response to detecting," depending on the context. Similarly, the phrase "if it is determined" or "if [a stated condition or event] is detected" may be construed to mean "upon determining" or "in response to determining" or "upon detecting [the stated condition or event]" or "in response to detecting [the stated condition or event]," depending on the context.

<u>SEISMIC ACQUISITION</u>

[0038] Figure 1 illustrates a schematic diagram of a marine-based seismic acquisition system 10 in accordance with implementations of various techniques described herein. In system 10, survey vessel 20 tows one or more seismic streamers 30 (one streamer 30 being depicted in Figure 1) behind the vessel 20. In one implementation, streamers 30 may be arranged in a spread in which multiple streamers

30 are towed in approximately the same plane at the same depth. Although various techniques are described herein with reference to a marine-based seismic acquisition system shown in Figure 1, it should be understood that other marine-based seismic acquisition system configurations may also be used. For instance, the streamers may be towed at multiple planes and/or multiple depths, such as in an over/under configuration. In one implementation, the streamers may be towed in a slanted configuration, where fronts of the streamers are towed shallower than tail ends of the streamers.

[0039] Seismic streamers 30 may be several thousand meters long and may contain various support cables, as well as wiring and/or circuitry that may be used to facilitate communication along the streamers 30. In general, each streamer 30 may include a primary cable where seismic sensors 58 that record seismic signals may be mounted. In one implementation, seismic sensors 58 may include hydrophones that acquire pressure data. In another implementation, seismic sensors 58 may include multi-component sensors such that each sensor is capable of detecting a pressure wavefield and at least one component of a particle motion that is associated with acoustic signals that are proximate to the sensor. Examples of particle motions include one or more components of a particle displacement, one or more components (i.e., inline (x), crossline (y) and vertical (z) components (see axes 59)) of a particle velocity and one or more components of a particle acceleration.

[0040] Depending on the particular survey need, the multi-component seismic receiver may include one or more hydrophones, geophones, particle displacement sensors, particle velocity sensors, accelerometers, pressure gradient sensors, or combinations thereof. In one implementation, the multi-component seismic sensor may be implemented as a single device, as depicted in Figure 1, or may be implemented as a plurality of devices. In another implementation, a particular multi-component seismic receiver may also include pressure gradient sensors, which constitute another type of particle motion sensors. Each pressure gradient sensor measures the change in the pressure wavefield at a particular point with respect to a particular direction. For example, one of the pressure gradient sensors may acquire seismic data indicative of, at a particular point, the partial derivative of the pressure wavefield with respect to the crossline direction, and another one of the pressure gradient sensors may acquire, at a particular point, seismic data indicative of the pressure data with respect to the inline direction.

[0041] Marine-based seismic data acquisition system 10 may also include one or more seismic sources 40, such as air guns and the like. In one implementation, seismic sources 40 may be coupled to, or towed by, the survey vessel 20. Alternatively, seismic sources 40 may operate independently of the survey vessel 20 in that the sources 40 may be coupled to other vessels or buoys.

[0042] As seismic streamers 30 are towed behind the survey vessel 20, acoustic signals 42, often referred to as “shots,” may be produced by seismic sources 40 and are directed down through a water column 44 into strata 62 and 68 beneath a water bottom surface 24. Acoustic signals 42 may be reflected from the various subterranean geological formations, such as formation 65 depicted in Figure 1.

[0043] The incident acoustic signals 42 that are generated by the sources 40 produce corresponding reflected acoustic signals, or pressure waves 60, which may be sensed by seismic sensors 58. In one implementation, pressure waves received and sensed by seismic sensors 58 may include “up going” pressure waves that propagate to the sensors 58 without reflection, as well as “down going” pressure waves that are produced by reflections of the pressure waves 60 from air-water boundary 31.

[0044] Seismic sensors 58 generate signals, called “traces,” which indicate the acquired measurements of the pressure wavefield and particle motion. The traces (i.e., seismic data) may be recorded and may be processed by signal processing unit 23 deployed on the survey vessel 20.

[0045] The goal of the seismic acquisition is to build up an image of a survey area for purposes of identifying subterranean geological formations, such as the exemplary geological formation 65. Subsequent analysis of the image may reveal probable locations of hydrocarbon deposits in subterranean geological formations. Analysis of the image may also be used for other purposes, such as Carbon Capture and Sequestration (CCS), geotechnical applications, and the like. In one implementation, portions of the analysis of the image may be performed on the seismic survey vessel 20, such as by the signal processing unit 23.

[0046] A particular seismic source 40 may be part of an array of seismic source elements (such as air guns, for example) that may be arranged in strings (gun strings, for example) of the array. Regardless of the particular composition of the seismic sources, the sources may be fired in a particular time sequence during the survey.

Although Figure 1 illustrates a marine-based seismic acquisition system, the marine-based seismic acquisition system is provided as an example of a seismic acquisition system that may correspond to the methods described herein. However, it should be noted that the methods described herein may also be performed on a land-based seismic acquisition system, a seabed-based seismic acquisition system, or a transition zone-based seismic acquisition system.

[0047] As mentioned above, a multicomponent streamer can be used to detect seismic data. In one implementation, both particle motion sensors and pressure sensors can be used. Each pressure sensor can have a hydrophone (or hydrophone pair) that is capable of detecting a pressure wavefield and each particle motion sensor can be a 3-component MEMS accelerometer. The MEMS accelerometer can be 2-component and only measure the vertical and the cross-line direction (i.e., directions that have components that are orthogonal to one another, or are a known angle to one another). The components that can be measured are inline (x), crossline (y) and vertical (z) of particle acceleration, velocity or otherwise movement. For rotation, the crossline (y) and the vertical (z) can be used, and the inline (x) need not be used.

[0048] There are various configurations the streamer can have. According to an implementation, the streamer can have a solid core, with the seismic sensors arranged at an outer location/portion in the radial direction of the central axis / core. The sensors can be configured in a number of ways, i.e., opposed to one another, at right angles to one another around the radius, or a combination thereof so that they are spaced around the radius at 90 degrees separation. The sensors can also be staggered in the inline (x) direction along the streamer in an "interleaved" manner. Also, the streamer could have a liquid or gel core and locate the sensors in various ways modified from those mentioned here. Similarly, the sensors can be pressure sensors that are spaced from one another and therefore detect particle acceleration by way of measuring the travel time and direction of a pressure wave. MEMS accelerometers can be used, but any accelerometer can be used even if it is not a MEMS. Modified hydrophones can be used, and in some cases they can merely be paired and/or rewired to detect particle movement.

[0049] The use of sensitive accelerometers and pressure sensors helps produce data that can be used to reconstruct / interpolate data between streamers. However, increased sensitivity of sensors introduces the issue of increased noise. Accelerometers that are used in seismic surveys are very sensitive in ways so that noise can be a much greater issue. Noise can be detrimental to the value of the data, as with too much noise the processing of the data to derive valuable information is compromised. Further, interpolation of the data to generated sensor/data readings for locations between the actual streamers in the crossline (y) direction can be compromised as well. In other words, the data should have the noise at a level or have noise attenuated and removed enough to allow for proper and more beneficial use of the data.

[0050] One or more quality control (QC) techniques and/or other techniques may be used to attenuate and/or remove such noise. Such techniques can be used for other implementations known to those skilled in the art, as well.

Rotation QC

[0051] In one implementation, a method to perform a real-time quality control (QC) on the estimated sensor orientation angles of a multisensory streamer in the presence of noise may be used. The maximum amount of the orientation angle estimation error and the mean absolute orientation angle error may be related to the amplitude of the low frequency noise. A method is provided to estimate the average amplitude of the low frequency noise in terms of the statisics of the measured data.

[0052] To acquire a high quality cross-line acceleration measurement, the sensor orientation angle can be measured with accuracy much better than a degree at any instant in time. Otherwise, static gravitational acceleration noise may dominate frequencies below ca. 15Hz on transverse particle acceleration measurement.

[0053] One implementation shows a sensor layout to have the torsional (angular) vibration noise separated from the signal and the transverse vibrations in wavenumber. Another implementation shows how to extract the torsional vibration noise from the raw measurement, and use this information to compute very accurate orientation angle for the crossline and vertical components of the particle acceleration about the inline axis. The estimate may be much more accurate than a degree at every instant in time.

[0054] The first step of the orientation correction may be estimation of the torsional vibration noise from the measurement. Figure 2 shows a frequency wavenumber plot of a noise record. Figure 2 shows the FK spectra of a noise recorded by transverse particle motion sensors. The noise includes transversal vibration noise 206 and torque noise 208. Also included in Figure 2 is a signal cone 204, which defines the boundaries in the f-k space for the expected seismic signal. The energy corresponding to the angular vibrations start at spatial Nyquist and has linear phase velocity. Since it is well separated from the seismic signal and the transverse vibrations below ca 30Hz, it can be estimated using a simple FK filter below ca 30Hz. The double integration of the angular acceleration gives the rapidly varying component of the orientation angle:

$$\phi(t,x)=\int_{-\infty}^{t'}\int_{-\infty}^{t''}AVN(t'',x)dt''dt' \qquad (1).$$

[0055] The double integral can be accurately computed at frequencies above ca 0.25Hz. Since angular vibration noise is well separated from translational acceleration its estimate is very reliable.

[0056] By first rotating the raw crossline and vertical acceleration data by ϕ, and then filtering the rotated data with a very narrow-band low-pass filter the sine and cosine of the slowly varying (low-frequency) part of the orientation angle θ are obtained:

$$\tilde{a}_Z = g\cos\theta + n_Z \quad , \quad \tilde{a}_Y = g\sin\theta + n_Y \qquad (2)$$

where (n_Z, n_Y) are low-frequency noise on the gravity measurements. The arctangent of the filtered data gives the estimate of the slowly varying orientation angle:

$$\hat{\theta} = \arctan(g\sin\theta + n_Y, g\cos\theta + n_Z) \quad (3).$$

[0057] The total orientation angle may be the sum of the two components:

$$\Theta = \hat{\theta} + \phi \quad (4).$$

[0058] Since angular vibration noise can be separated from translational acceleration, its estimate is very reliable. However, the slowly-varying part of the orientation may get affected from very strong low-frequency noise. In one implementation, the amount of the orientation angle error can be related to the amplitude of the low frequency noise. In particular, an estimate of the noise amplitude can be obtained from the measurement.

[0059] The tangent of the estimated orientation angle may be the ratio of the rotated and filtered measurements in (2):

$$\tan(\hat{\theta}) = \tan(\theta + \Delta\theta) = \frac{g\sin\theta + n_Y}{g\cos\theta + n_Z} \quad (5)$$

where $\Delta\theta$ represents the corresponding angle error. The polar coordinates may give the representation of the noise in terms of its amplitude r and phase ψ:

$$\begin{aligned} r &= \sqrt{n_Y^2 + n_Z^2} \\ \psi &= \arctan(n_Y, n_Z) \end{aligned} \quad (6).$$

[0060] The tangent of the sum of the angles can be written in terms of the tangents of the angles:

$$\tan(\theta + \Delta\theta) = \frac{\tan\theta + \tan\Delta\theta}{1 - \tan\theta\tan\Delta\theta} \quad (7).$$

[0061] Combining (5), (6), and (7) we get the following expression:

$$\frac{\tan\theta + \tan\Delta\theta}{1 - \tan\theta\tan\Delta\theta} = \frac{g\sin\theta + r\sin\psi}{g\cos\theta + r\sin\psi} \quad (8).$$

[0062] We can solve (8) for the tangent of the angle error:

$$\tan\Delta\theta = \frac{r\sin(\psi - \theta)}{g + r\cos(\psi - \theta)} \quad (9).$$

[0063] In terms of the actual orientation angle θ, the phase of the noise ψ, and the amplitude of the noise r, the orientation angle θ can be a slowly-varying function of time, and the noise phase and the amplitude may be stochastic processes. The instantaneous value of the angle error may change depending on the particular value of the actual orientation angle, and the noise realizations. However, the maximum angle error may be bounded by the amplitude of the noise, and is independent of the actual orientation angle:

$$|\Delta\theta| \le \arctan(r / g) \quad (10).$$

[0064] The maximum angle error may occur when the noise vector is orthogonal to the measurement, vector, i.e., $|\psi - \theta| = \pi / 2$. On the other hand, when the noise vector is parallel to the measurement vector, the estimated angle may be correct regardless of the amplitude of the noise:

$$|\Delta\theta| = 0 \quad , \quad \psi = \theta \qquad (11).$$

[0065] Statistics of the angle error may give valuable information on the accuracy of the estimated orientation angles. For instance, the mean absolute orientation angle error may be defined as:

$$E|\Delta\theta| = \frac{1}{2\pi}\int_0^{2\pi}\left|\arctan\frac{r\sin(\theta+\varphi)}{g+r\cos(\theta-\varphi)}\right| f_\Psi(\psi)d\psi \qquad (12)$$

where $f_\Psi(\psi)$ may be the probability density function of the phase of the noise. When the noises on orthogonal components are independent and identically distributed, the phase ψ may be a uniform random variable over $[0,2\pi]$, and the mean absolute orientation angle error may be:

$$E|\Delta\theta| = \frac{1}{2\pi}\int_0^{2\pi}\left|\arctan\left(\frac{r\sin(\theta+\varphi)}{g+r\cos(\theta-\varphi)}\right)\right| d\varphi \cong \frac{1}{\pi}\ln\frac{g+r}{g-r} \qquad (13).$$

[0066] The approximation may be valid when the noise amplitude is smaller than 1*g*. As an example, the approximation may be valid when the amplitude of the noise is r=1m*g*, $E|\Delta\theta|$=0.0365deg, and when the amplitude of the noise is r=10m*g*, $E|\Delta\theta|$=0.366deg.

[0067] We can relate the expected amount of angle error to the noise amplitude. Hence, to find the accuracy of the rotation in the presence of strong low frequency noise, we may estimate the noise amplitude from the data. An upper bound on the average noise amplitude may be found by computing the mean of the norm square of the measurement vector in (2):

$$\begin{aligned} E[\tilde{a}_Z^2 + \tilde{a}_Y^2] &= E[g^2 + 2g\cos\theta n_Z + 2g\sin\theta n_Y + r^2] \\ &= g^2 + E[r^2] \end{aligned} \qquad (14)$$

and using the Cauchy Schwarz inequality:

$$E[r] \le \sqrt{E[r^2]} = \sqrt{E[\tilde{a}_Z^2 + \tilde{a}_Y^2] - g^2} \qquad (15).$$

<u>Twist QC</u>

[0068] In one implementation, a method to perform a real-time quality control (QC) of the cable twists very densely along the streamer (essentially at every sensor position) may be used. The method may estimate the cable twist continuously as a function of the inline offset in real-time by using the acquired particle acceleration data. The method may not require the knowing the previous state of the cable or the state of the active steering devices (birds) along the cable.

[0069] Although the twist in the cable may not affect the data quality, the ability to generate real-time twist information may help a crew monitor the state of the cable and prevent excessive twisting of cables that may physically damage the sections.

[0070] One implementation shows a sensor layout to have the torsional (angular) vibration noise separated from the signal and the transverse vibrations in wavenumber. Another implementation shows how to accurately estimate the orientation angle of the towed multi-sensor measurements, and rotate the acquired data.

[0071] A streamer towed behind a seismic vessel may experience twists along its length. The twist may be caused by the rotational imbalances, by active steering devices, or if some debris get trapped on the streamer. The twist may have no effect on the scalar pressure wavefield, and it may have no negative effect on the acquired particle acceleration data too as long as the sensor orientation is accurately computed.

[0072] Monitoring the twist in the cable may be used to ensure the mechanical health of the cables. Although streamers can tolerate a large number of twists along their length, if the number of twists become excessive there could be physical damage to the cable or the wires within the cable.

[0073] One known technique proposes the importance of the twist from a cable steering point of view. It discusses that if the twist is not accounted for, the birds may use all their available splay angles to counter the twist in the streamer. It describes a method to estimate the streamer twist by weight function filtering the splay angle measurements from the birds. The estimated twist will be available at bird positions which is typically every 200m or 400m.

[0074] In one implementation, an estimate of the cable twist may be made using the seismic data acquired by densely spaced particle motion sensors. One way to estimate the cable twist is to find the orientation angle of the sensors, remove 2π phase jumps from the data by using the phase “unwrap” operation, and then compute the inline gradient:

$$\tau(t,x)=\frac{1}{2\pi}\frac{\partial\theta(t,x)}{\partial x} \quad (16)$$

where $\tau(t,x)$ is the number of local cable twists (full cable rotations) as a function of time and inline offset; and $\theta(t,x)$ is the orientation of the particle motion sensor about the inline axis.

[0075] Phase unwrapping can be avoided by computing the twist rate directly from the DC (low frequencies) of the acquired data. First the slowly varying part of the orientation angle can be expressed as arctangent of the low-pass filtered crossline and vertical measurements:

$$\theta(t,x)=\arctan\left(\frac{a_{Y,LP}(t,x)}{a_{Z,LP}(t,x)}\right) \quad (17).$$

[0076] Substituting (17) into (16) gives the twist rate:

$$\tau(t,x)=\frac{1}{2\pi}\frac{\frac{\partial a_{Y,LP}(t,x)}{\partial x}a_{Z,LP}(t,x)-\frac{\partial a_{Z,LP}(t,x)}{\partial x}a_{Y,LP}(t,x)}{a_{Z,LP}^{2}(t,x)+a_{Y,LP}^{2}(t,x)} \quad (18).$$

[0077] For a horizontal (flat) cable, there may be negligible gravity along the inline cable axis. Therefore, the denominator of (18) can be approximated as the square of the earth’s gravitational acceleration, i.e., $1g$:

$$\tau(t,x)=\frac{1}{2\pi g}\left[\frac{\partial a_{Y,LP}(t,x)}{\partial x}a_{Z,LP}(t,x)-\frac{\partial a_{Z,LP}(t,x)}{\partial x}a_{Y,LP}(t,x)\right] \quad (19).$$

[0078] The integral of the twist rate may be the accumulated number of full streamer rotations with respect to the position of the first sensor in the streamer:

$$\Gamma(t,x)=\int_{0}^{x}\tau(t,x')dx' \quad (20).$$

[0079] Figure 3 shows the accumulated number of cable twists along a 3km streamer. The light triangles, e.g., triangles 305, indicate bird positions, and dark triangles, e.g., triangles 310 indicate streamer retrieval devices (SRDs).

[0080] These expressions may allow computation and monitoring of the cable twist in real-time and continuously along the length of the streamer. Since the twist information may be derived from the seismic data, the cable twist may be available even when the communication with the birds is lost. The method may not require knowledge of the initial state of the cable. Therefore, it may be more reliable than the twist counting algorithms that monitor the number of the times the birds rotate 180 degrees.

Estimation of Tension and Bending Stiffness

[0081] In one implementation, a method may be used to dynamically estimate the tension along a streamer. The method may be based on the concepts that: 1) the acquired seismic data may contain transversal vibration noise (in addition to the other noise types of seismic signal), and 2) the frequency-wavenumber dispersion relationship of the acquired vibration noise may relate the bending stiffness of the cable to the tension along the cable. Hence, the method may use the bending stiffness of the cable (calculated from material properties) and the frequency-wavenumber dispersion relationship of the transversal vibration noise to estimate the tension continuously along the streamer. In another implementation, if the tension is measured at certain locations, the method can be used to estimate the bending stiffness continuously along the streamer.

[0082] In another implementation, a method may use the tension measurements at certain locations to estimate the added mass effect. The estimated added mass effect and the frequency-wavenumber dispersion relationship of the transverse vibration noise may be used to estimate the tension and bending stiffness of the cable continuously along the cable.

[0083] The dynamically estimated tension can be monitored to ensure that it does not exceed the operating ranges anywhere along the cable. The estimate of the bending stiffness along the cable could be compared with the estimate from material properties to monitor the changes in the bending stiffness due to wear and tear as a function of time.

[0084] The frequency-wavenumber dispersion relationship of a solid streamer can be approximated to a good degree by the transverse (flexural) vibration of an infinitely long uniform beam subject to axial tension. The equation of motion for the transverse vibration $\psi(t,x)$ of the beam may be defined by a fourth-order partial differential equation with constant coefficients:

$$EI\frac{\partial^4\psi(x,t)}{\partial x^4}-T\frac{\partial^2\psi(x,t)}{\partial x^2}+m\frac{\partial^2\psi(x,t)}{\partial t^2}=h(x,t) \qquad (21)$$

where t is time, x is the coordinate of the inline-axis, E is the Young's modulus in Pa, I is the area moment of inertia in m^4, T is the axial tension load in N, m is the mass per unit length in kg/m, and $h(x,t)$ is the external force per unit length. For a stationary and neutrally buoyant streamer, the mass per unit length may be given by $m=\pi d^2\rho/4$ where ρ is the density of sea water in kg/m^3 and d is the outer diameter. When the streamer is towed in the fluid medium, the density ρ may be replaced with ρ_a to account for added mass effect as the towed streamer moves some volume of fluid with it.

[0085] The eigenfunctions of the corresponding homogenous partial differential equation may define the natural frequencies and wavenumbers, i.e., the frequencies and wavenumbers at which the vibration noise has very high amplitudes. The eigenfunctions of the homogenous equation may have the following form: $g(x,t)=e^{j2\pi(ft+kx)}$ where the k is the wavenumber and f is the frequency. Substituting $g(x,t)$ into the corresponding homogenous PDE, the following may be obtained:

$$4\pi^2\frac{k^4}{f^2}EI+\frac{k^2}{f^2}T-\frac{\pi d^2\rho_a}{4}=0 \qquad (22).$$

[0086] The dispersion relationship may define the natural frequencies in terms of the natural wavenumbers (or vice versa):

$$f(k)=\frac{2\sqrt{T+EI4\pi k^2}}{d\sqrt{\pi\rho_a}}k \qquad (23).$$

[0087] The corresponding velocity can be obtained as a function of natural frequencies or wavenumbers:

$$v_p(k) \equiv \frac{f(k)}{k} = \frac{2}{d}\sqrt{\frac{4\pi^2 k^2 EI + T}{\pi \rho_a}} \qquad (24).$$

[0088] The dispersion relationship given in equation (22) may relate the mechanical properties of the cable (the Young's modulus E, the area moment of inertia I, the outer diameter d); the tension T applied to the cable; and the mass effect due to the surrounding fluid characterized by ρ_a. The natural frequency and wavenumbers can be estimated by using an FK domain analysis. After the frequencies f and the wavenumbers k which satisfy the equation (22) are estimated from an FK domain analysis, equation (22) may define a linear set of equations in three variables: bending stiffness EI, the tension T and the added mass density ρ_a.

[0089] The bending stiffness of the cable might be known from the physical properties of the material; the tension might be known with the use of a tension cell; or the added mass density might be known as a result of previous analyses. When the value of any of these variables is known or has been measured by some other means, the other two variables can be estimated by using the dispersion relationship defined by equation (22).

[0090] As an example, suppose that the FK domain analysis gives N natural wavenumbers $k_i = k_1, k_2, \ldots, k_N$ and the corresponding N natural frequencies $f_i = f_1, f_2, \ldots, f_N$. If the bending stiffness of the cable has been calculated from the material properties, then the equation (22) can be rearranged as a system of N equations in two unknowns:

$$\left(\frac{\pi d^2}{4}\right)\rho_a - \left(\frac{k_i^2}{f_i^2}\right)T = \left(4\pi^2 \frac{k_i^4}{f_i^2} EI\right) \quad , \quad i = 1, 2, \ldots, N \qquad (25).$$

[0091] The unknowns ρ_a and T can be estimated by solving the linear set of equations, for instance, by using a least squares inversion.

[0092] As another example, if the tension of the streamer has been measured by using a tension cell, then the equation (22) can be rearranged as a system of N equations in two unknowns:

$$\left(4\pi^2 \frac{k_i^4}{f_i^2}\right) EI + \left(-\frac{\pi d^2}{4}\right)\rho_a = \left(\frac{k_i^2}{f_i^2} T\right) \quad , \quad i = 1, 2, \ldots, N \quad (26).$$

[0093] The unknowns EI and ρ_a can be estimated by solving the linear set of equations, for instance, by using a least squares inversion.

[0094] Yet as another example, if the added mass effect is known, then the equation (22) can be rearranged as a system of N equations in two unknowns:

$$\left(4\pi^2 \frac{k_i^4}{f_i^2}\right) EI + \left(\frac{k_i^2}{f_i^2}\right) T = \left(\frac{\pi d^2}{4}\rho_a\right) \quad , \quad i = 1, 2, \ldots, N \quad (27).$$

[0095] The unknowns EI and T can be estimated by solving the linear set of equations, for instance, by using a least squares inversion.

[0096] Other variations are possible. As an example, the tension measurement could be done at least one location; the bending stiffness and added mass effect can be estimated based on the corresponding tension measurement; and the estimated value of the added mass effect can be used to estimate the tension at locations where there is no tension cell.

[0097] Other variations of the method are possible. For instance, from (24) it follows that the square of the phase velocity may be a linear function of the square of the natural wavenumber:

$$v_p^2(k) \equiv ak^2 + b \quad (28)$$

where a and b are given by:

$$a = \frac{16\pi EI}{d^2 \rho_{fluid}} \quad (29)$$

$$b = \frac{4T}{\pi d^2 \rho_{fluid}} \quad (30).$$

[0098] The values of a and b can be experimentally estimated by fitting a line to the phase velocity-squared versus wavenumber-squared plot.

[0099] When the bending stiffness is known, the equations (29) and (30) can be solved for the tension and the added mass density:

$$T = \frac{4\pi^2 b}{a} EI \qquad \rho_{fluid} = \frac{16\pi}{d^2 a} EI \qquad (31).$$

[00100] When the tension is known, the equations (29) and (30) can be solved for the bending stiffness and the added mass density:

$$EI = \frac{a}{4\pi^2 b} T \qquad \rho_{fluid} = \frac{4}{\pi d^2 b} T \qquad (32).$$

[00101] When the added mass density is known, the equations (29) and (30) can be solved for the bending stiffness and the tension:

$$EI = \frac{d^2 a}{16\pi} \rho_{fluid} \qquad T = \frac{\pi d^2 b}{4} \rho_{fluid} \qquad (33).$$

<u>Rotation QC</u>

[00102] Figure 4 illustrates a flow diagram of a method for rotation QC in accordance with implementations of various techniques described herein. At block 405, seismic data from a group of seismic sensors disposed on a plurality of seismic streamers is received. At block 410, an estimation of expected low frequency noise level is computed. The expected low frequency noise level, $E[r]$, may be computed as shown above in Equation 14 and Equation 15.

[00103] In one implementation, the low frequency noise level may be computed in accordance with the following approach. Low-pass filtered data is computed by applying a high cut filter, e.g., a low pass filter, in the time domain to raw data, e.g., seismic data or particle motion data a_Z, a_Y, to produce $\tilde{a}_Z, \tilde{a}_Y$. The squared two-norm of the low-pass filtered data, $\tilde{a}_Z^2 + \tilde{a}_Y^2$ is computed. The mean of the squared two-norm is estimated, $E[\tilde{a}_Z^2 + \tilde{a}_Y^2]$. The average noise level is estimated, for example, using the following expression: $E[r] \cong \sqrt{E[\tilde{a}_Z^2 + \tilde{a}_Y^2] - g^2}$.

[00104] An orientation angle error of at least one of the seismic sensors in the group of seismic sensors is estimated based on the low-frequency noise in the seismic data. The estimated orientation angle error may be a maximum orientation angle error, a mean absolute orientation angle error, or both. At block 415, a maximum orientation angle error is determined. The maximum orientation angle error may be determined using the estimated average noise level instead of the amplitude of the noise, e.g., by substituting $E[r]$for r in Equation 10.

[00105] At block 420, a mean absolute orientation angle error is determined. The mean absolute orientation angle error may be determined using the estimated average noise level instead of the amplitude of the noise, e.g., by substituting $E[r]$for r in Equation 13.

[00106] At block 425, the acquired seismic data may be analyzed based on the estimated orientation angle error. The orientation angle error may provide an indication that seismic data is useable or un-useable. Some examples of elements that may affect orientation angle error are a noisy environment and/or strong currents. Because of the aforementioned conditions, the acquired data may be rendered unuseable. Estimation of orientation may be used as a quality metric and the error may be used to provide quality control (QC) for the seismic survey data.

[00107] At block 430, the seismic acquisition may be managed based on the analysis. In one implementation, the data is being acquired in real-time. By checking the quality of the acquired data, a determination can be made as to whether the data is acceptable or unacceptable. In view of this determination, a decision can be made to stop a seismic survey, continue a seismic survey or reacquire the seismic data.

[00108] In one implementation, instead of performing the analysis during acquisition, the analysis may be performed post acquisition. Based on the analysis, e.g., of orientation angle error, a decision can be made to keep or discard the acquired data.

[00109] It should be understood that while method 400 indicates a particular order of execution of operations, in some implementations, certain portions of the operations might be executed in a different order. Further, in some implementations, additional operations or blocks may be added to the method 400. Likewise, some operations or blocks may be omitted.

Twist QC

[00110] Figure 5 illustrates a flow diagram of a method for twist QC in accordance with implementations of various techniques described herein. At block 505, seismic data may be received from a group of seismic sensors disposed on a plurality of seismic streamers. At block 510, an estimation of the twist rate, τ, along a length of at least one seismic streamers is computed based on the seismic data.

[00111] In one implementation, the twist rate may be computed in accordance with the following approach as shown above in relation to Equation 19. Low-pass filtered data is computed by applying a high cut filter, e.g., low pass filter, in the time domain to raw data, e.g., particle motion data a_Z, a_Y, to produce $a_{Z,LP}, a_{Y,LP}$. The gradient in space, or in the space domain, $\partial a_{Z,LP} / \partial x, \partial a_{Y,LP} / \partial x$, of the low-pass filtered data is then determined. The gradient in space, or in the space domain, may be further described as a derivative in a special direction, e.g., along the streamer. The low-pass filtered data and the gradient are then used to compute the twist rate. This may be accomplished by substituting the computed $a_{Z,LP}, a_{Y,LP}$ and $\partial a_{Z,LP} / \partial x, \partial a_{Y,LP} / \partial x$ nto Equation 19.

[00112] In another implementation, the twist rate may be computed in accordance with the following approach as shown above in relation to Equation 16. Low-pass filtered data is computed by applying a high cut filter, e.g., low pass filter, in the time domain to raw data, e.g., particle motion data a_Z, a_Y, to produce $a_{Z,LP}, a_{Y,LP}$. The orientation angle of at least one seismic sensor is then determined. In one implementation, the orientation angle is determined by computing the arctangent of $a_{Z,LP}, a_{Y,LP}$, as shown in Equation 17. Phase unwrapping of the orientation angle may be performed, e.g., by removing 2π phase jumps from the orientation angle. The twist rate, τ, is computed by differentiating the orientation angle in space, or in the space domain, e.g., as shown in Equation 16.

[00113] At block 515, an accumulated number of twists along the length of the at least one seismic streamer may be estimated. In one implementation, the accumulated number of twists may be estimated by integrating the twist rate in space, or in the space domain. The accumulated number of twists, Γ, may be estimated, for example, by integrating the twist rate, τ, as shown in Equation 20.

[00114] At block 520, a determination is made as to whether the number of twists exceeds a threshold. At block 525, based on the threshold, a determination is made as to whether the at least one seismic streamer is to be replaced or untwisted. If a determination is made that the number of twists exceeds a certain threshold, the cable can be untwisted. Steering devices may be used to untwist the cable, for example, by sending specific commands to the steering devices, e.g., birds, to undo the twists. The number of twists can also be used to determine whether a section of cable should be replaced, for example, when a determination is made that the number of twists for that section of cable exceeds a certain threshold.

[00115] It should be understood that while method 500 indicates a particular order of execution of operations, in some implementations, certain portions of the operations might be executed in a different order. Further, in some implementations, additional operations or blocks may be added to the method 500. Likewise, some operations or blocks may be omitted.

<u>Estimation of Physical Properties from Seismic Data</u>

[00116] Figure 6 illustrates a flow diagram of a method for estimation of physical properties, e.g., tension, bending stiffness and/or density from seismic data in accordance with implementations of various techniques described herein. At block 605, raw data, e.g., seismic data or particle motion data from a group of seismic sensors disposed on a plurality of seismic streamers is received.

[00117] At block 610, at least two physical properties of the plurality of seismic streamers are estimated using the acquired seismic data and transversal vibration noise found in the seismic streamers. A Fourier transform of the raw data, e.g., over time and space (FK transform) may be computed. The FK transform converts the seismic data from the time-space domain to the frequency-wavenumber domain. An FK analysis is performed to identify a plurality of pairs of natural frequencies and wavenumbers that lie on a dispersion curve (e.g., a model of transverse vibration noise) as peaks of the FK transform. The FK analysis determines the peaks on the spectra. In one implementation, there are N pairs of natural frequencies and wavenumbers (f_i, k_i) and the dispersion curve may follow the approach as shown in Equation 22. A linear system of equations with N equations and two unknowns (e.g., the physical properties of block 610) may be set. Because there is an over-determined system of equations, i.e., more equations than unknowns, the problem of two unknowns may be solved by a least squares inversion.

[00118] In one implementation, as shown in Equation 26, tension, T, is known and the unknowns are bending stiffness, EI, and density, ρ_a. The physical properties, EI and ρ_a may be determined from an over-determined system of equations by using a least-squares inversion.

[00119] In one implementation, as shown in Equation 27, density, ρ_a, is known and the unknowns are tension, T, and bending stiffness, EI. The physical properties, T and EI, may be determined from an over-determined system of equations by using a least-squares inversion.

[00120] It should be understood that while method 600 indicates a particular order of execution of operations, in some implementations, certain portions of the operations might be executed in a different order. Further, in some implementations, additional operations or blocks may be added to the method 600. Likewise, some operations or blocks may be omitted.

COMPUTING SYSTEMS

[00121] Implementations of various technologies described herein may be operational with numerous general purpose or special purpose computing system environments or configurations. Examples of well known computing systems, environments, and/or configurations that may be suitable for use with the various technologies described herein include, but are not limited to, personal computers, server computers, hand-held or laptop devices, multiprocessor systems, microprocessor-based systems, set top boxes, programmable consumer electronics, network PCs, minicomputers, mainframe computers, smartphones, smartwatches, personal wearable computing systems networked with other computing systems, tablet computers, and distributed computing environments that include any of the above systems or devices, and the like.

[00122] The various technologies described herein may be implemented in the general context of computer-executable instructions, such as program modules, being executed by a computer. Generally, program modules include routines, programs, objects, components, data structures, etc. that performs particular tasks or implement particular abstract data types. While program modules may execute on a single computing system, it should be appreciated that, in some implementations, program modules may be implemented on separate computing systems or devices adapted to communicate with one another. A program module may also be some combination of hardware and software where particular tasks performed by the program module may be done either through hardware, software, or both.

[00123] The various technologies described herein may also be implemented in distributed computing environments where tasks are performed by remote processing devices that are linked through a communications network, e.g., by hardwired links, wireless links, or combinations thereof. The distributed computing environments may span multiple continents and multiple vessels, ships or boats. In a distributed computing environment, program modules may be located in both local and remote computer storage media including memory storage devices.

[00124] Figure 7 illustrates a schematic diagram of a computing system 700 in which the various technologies described herein may be incorporated and practiced. Although the computing system 700 may be a conventional desktop or a server computer, as described above, other computer system configurations may be used.

[00125] The computing system 700 may include a central processing unit (CPU) 730, a system memory 726, a graphics processing unit (GPU) 731 and a system bus 728 that couples various system components including the system memory 726 to the CPU 730. Although one CPU is illustrated in Figure 7, it should be understood that in some implementations the computing system 700 may include more than one CPU. The GPU 731 may be a microprocessor specifically designed to manipulate and implement computer graphics. The CPU 730 may offload work to the GPU 731. The GPU 731 may have its own graphics memory, and/or may have access to a portion of the system memory 726. As with the CPU 730, the GPU 731 may include one or more processing units, and the processing units may include one or more cores. The system bus 728 may be any of several types of bus structures, including a memory bus or memory controller, a peripheral bus, and a local bus using any of a variety of bus architectures. By way of example, and not limitation, such architectures include Industry Standard Architecture (ISA) bus, Micro Channel Architecture (MCA) bus, Enhanced ISA (EISA) bus, Video Electronics Standards Association (VESA) local bus, and Peripheral Component Interconnect (PCI) bus also known as Mezzanine bus. The system memory 726 may include a read-only memory (ROM) 712 and a random access memory (RAM) 746. A basic input/output system (BIOS) 714, containing the basic routines that help transfer information between elements within the computing system 700, such as during start-up, may be stored in the ROM 712.

[00126] The computing system 700 may further include a hard disk drive 750 for reading from and writing to a hard disk, a magnetic disk drive 752 for reading from and writing to a removable magnetic disk 756, and an optical disk drive 754 for reading from and writing to a removable optical disk 758, such as a CD ROM or other optical media. The hard disk drive 750, the magnetic disk drive 752, and the optical disk drive 754 may be connected to the system bus 728 by a hard disk drive interface 756, a magnetic disk drive interface 758, and an optical drive interface 750, respectively. The drives and their associated computer-readable media may provide nonvolatile storage of computer-readable instructions, data structures, program modules and other data for the computing system 700.

[00127] Although the computing system 700 is described herein as having a hard disk, a removable magnetic disk 756 and a removable optical disk 758, it should be appreciated by those skilled in the art that the computing system 700 may also include other types of computer-readable media that may be accessed by a computer. For example, such computer-readable media may include computer storage media and communication media. Computer storage media may include volatile and non-volatile, and removable and non-removable media implemented in any method or technology for storage of information, such as computer-readable instructions, data structures, program modules or other data. Computer storage media may further include RAM, ROM, erasable programmable read-only memory (EPROM), electrically erasable programmable read-only memory (EEPROM), flash memory or other solid state memory technology, CD-ROM, digital versatile disks (DVD), or other optical storage, magnetic cassettes, magnetic tape, magnetic disk storage or other magnetic storage devices, or any other medium which can be used to store the desired information and which can be accessed by the computing system 700. Communication media may embody computer readable instructions, data structures, program modules or other data in a modulated data signal, such as a carrier wave or other transport mechanism and may include any information delivery media. The term "modulated data signal" may mean a signal that has one or more of its characteristics set or changed in such a manner as to encode information in the signal. By way of example, and not limitation, communication media may include wired media such as a wired network or direct-wired connection, and wireless media such as acoustic, RF, infrared and other wireless media. The computing system 700 may also include a host adapter 733 that connects to a storage device 735 via a small computer system interface (SCSI) bus, a Fiber Channel bus, an eSATA bus, or using any other applicable computer bus interface. Combinations of any of the above may also be included within the scope of computer readable media.

[00128] A number of program modules may be stored on the hard disk 750, magnetic disk 756, optical disk 758, ROM 712 or RAM 716, including an operating system 718, one or more application programs 720, program data 724, and a database system 748. The application programs 720 may include various mobile applications ("apps") and other applications configured to perform various methods and techniques described herein. The operating system 718 may be any suitable operating system that may control the operation of a networked personal or server computer, such as Windows® XP, Mac OS® X, Unix-variants (e.g., Linux® and BSD®), and the like.

[00129] A user may enter commands and information into the computing system 700 through input devices such as a keyboard 762 and pointing device 760. Other input devices may include a microphone, joystick, game pad, satellite dish, scanner, or the like. These and other input devices may be connected to the CPU 730 through a serial port interface 742 coupled to system bus 728, but may be connected by other interfaces, such as a parallel port, game port or a universal serial bus (USB). A monitor 734 or other type of display device may also be connected to system bus 728 via an interface, such as a video adapter 732. In addition to the monitor 734, the computing system 700 may further include other peripheral output devices such as speakers and printers.

[00130] Further, the computing system 700 may operate in a networked environment using logical connections to one or more remote computers 774. The logical connections may be any connection that is commonplace in offices, enterprise-wide computer networks, intranets, and the Internet, such as local area network (LAN) 756 and a wide area network (WAN) 766. The remote computers 774 may be another a computer, a server computer, a router, a network PC, a peer device or other common network node, and may include many of the elements describes above relative to the computing system 700. The remote computers 774 may also each include application programs 770 similar to that of the computer action function.

[00131] When using a LAN networking environment, the computing system 700 may be connected to the local network 776 through a network interface or adapter 744. When used in a WAN networking environment, the computing system 700 may include a router 764, wireless router or other means for establishing communication over a wide area network 766, such as the Internet. The router 764, which may be internal or external, may be connected to the system bus 728 via the serial port interface 752. In a networked environment, program modules depicted relative to the computing system 700, or portions thereof, may be stored in a remote memory storage device 772. It will be appreciated that the network connections shown are merely examples and other means of establishing a communications link between the computers may be used.

[00132] The network interface 744 may also utilize remote access technologies (e.g., Remote Access Service (RAS), Virtual Private Networking (VPN), Secure Socket Layer (SSL), Layer 2 Tunneling (L2T), or any other suitable protocol). These remote access technologies may be implemented in connection with the remote computers 774.

[00133] It should be understood that the various technologies described herein may be implemented in connection with hardware, software or a combination of both. Thus, various technologies, or certain aspects or portions thereof, may take the form of program code (i.e., instructions) embodied in tangible media, such as floppy diskettes, CD-ROMs, hard drives, or any other machine-readable storage medium wherein, when the program code is loaded into and executed by a machine, such as a computer, the machine becomes an apparatus for practicing the various technologies. In the case of program code execution on programmable computers, the computing device may include a processor, a storage medium readable by the processor (including volatile and non-volatile memory and/or storage elements), at least one input device, and at least one output device. One or more programs that may implement or utilize the various technologies described herein may use an application programming interface (API), reusable controls, and the like. Such programs may be implemented in a high level procedural or object oriented programming language to communicate with a computer system. However, the program(s) may be implemented in assembly or machine language, if desired. In any case, the language may be a compiled or interpreted language, and combined with hardware implementations. Also, the program code may execute entirely on a user's computing device, on the user's computing device, as a stand-alone software package, on the user's computer and on a remote computer or entirely on the remote computer or a server computer.

[00134] The system computer 700 may be located at a data center remote from the survey region. The system computer 700 may be in communication with the receivers (either directly or via a recording unit, not shown), to receive signals indicative of the reflected seismic energy. These signals, after conventional formatting and other initial processing, may be stored by the system computer 700 as digital data in the disk storage for subsequent retrieval and processing in the manner described above. In one implementation, these signals and data may be sent to the system computer 700 directly from sensors, such as geophones, hydrophones and the like. When receiving data directly from the sensors, the system computer 700 may be described as part of an in-field data processing system. In another implementation, the system computer 700 may process seismic data already stored in the disk storage. When processing data stored in the disk storage, the system computer 700 may be described as part of a remote data processing center, separate from data acquisition. The system computer 700 may be configured to process data as part of the in-field data processing system, the remote data processing system or a combination thereof.

[00135] Those with skill in the art will appreciate that any of the listed architectures, features or standards discussed above with respect to the example computing system 700 may be omitted for use with a computing system used in accordance with the various embodiments disclosed herein because technology and standards continue to evolve over time.

[00136] Of course, many processing techniques for collected data, including one or more of the techniques and methods disclosed herein, may also be used successfully with collected data types other than seismic data. While certain implementations have been disclosed in the context of seismic data collection and processing, those with skill in the art will recognize that one or more of the methods, techniques, and computing systems disclosed herein can be applied in many fields and contexts where data involving structures arrayed in a three-dimensional space and/or subsurface region of interest may be collected and processed, *e.g.*, medical imaging techniques such as tomography, ultrasound, MRI and the like for human tissue; radar, sonar, and LIDAR imaging techniques; and other appropriate three-dimensional imaging problems.

[00137] While the foregoing is directed to implementations of various technologies described herein, other and further implementations may be devised without departing from the basic scope thereof. Although the subject matter has been described in language specific to structural features and/or methodological acts, it is to be understood that the subject matter defined in the appended claims is not limited to the specific features or acts described above. Rather, the specific features and acts described above are disclosed as example forms of implementing the claims.

What Is Claimed Is:

1. A method, comprising:

receiving seismic data that had been acquired from a group of seismic sensors disposed on a plurality of seismic streamers;

estimating low-frequency noise in the seismic data;

estimating an orientation angle error of at least one of the seismic sensors in the group of seismic sensors based on the low-frequency noise in the seismic data;

analyzing the seismic data based on the estimated orientation angle error; and

managing an acquisition of the seismic data based on the analysis.

2. The method of claim 1, wherein the seismic data is analyzed and managed in real time during a seismic survey.

3. The method of claim 2, wherein managing the acquisition comprises stopping a seismic survey, continuing the seismic survey or reacquiring the seismic survey based on the analysis.

4. The method of claim 1, wherein the seismic data is analyzed and managed after acquisition.

5. The method of claim 1, wherein the estimated orientation angle error comprises at least one of an estimated maximum orientation angle error and a mean absolute orientation error.

6. The method of claim 5, wherein estimating low-frequency noise in the seismic data further comprising:

computing low-pass filtered data by applying a high cut filter in the time domain to the seismic data;

computing a squared two-norm of the low-pass filtered data;

estimating a mean of the squared two-norm; and

estimating an average noise level based on at least the estimated mean.

7. The method of claim 6, wherein the mean absolute orientation angle error is determined by substituting the estimated average noise level for the amplitude of the noise.

8. The method of claim 6, wherein the maximum orientation angle error is determined by substituting the estimated average noise level for the amplitude of the noise.

9. A method, comprising:

receiving seismic data that had been acquired from a group of seismic sensors disposed on a plurality of seismic streamers; and

estimating a twist rate along a length of at least one of the plurality of seismic streamers based on the seismic data;

estimating an accumulated number of twists along the length;

determining whether the accumulated number of twists exceeds a threshold; and

determining, based on the threshold, whether the at least one of the plurality of seismic streamers is to be replaced or untwisted.

10. The method of claim 9, wherein estimating the twist rate comprises computing low-pass filtered data by applying a high cut filter in the time domain to the seismic data.

11. The method of claim 10, wherein estimating the twist rate comprises:

determining a gradient in space of the low-pass filtered data; and

using the low-pass filtered data and the gradient to estimate the twist rate.

12. The method of claim 10, wherein estimating the twist rate comprises:

determining an orientation angle of the at least one seismic sensor;

performing phase unwrapping of the orientation angle; and

computing the twist rate by differentiating the orientation angle in space.

13. The method of claim 12, wherein the orientation angle is determined by computing an arctangent of the low-pass filtered data.

14. The method of claim 12, wherein phase unwrapping is performed by removing 2π phase jumps from the orientation angle.

15. A method, comprising:

receiving seismic data that had been acquired from a group of seismic sensors disposed on a plurality of seismic streamers; and

estimating at least two physical properties of the plurality of seismic streamers using the acquired seismic data and transversal vibration noise found in the seismic streamers.

16. The method of claim 15, wherein estimating the at least two physical properties comprises:

computing a Fourier transform of the seismic data;

performing an frequency-wavenumber domain analysis to identify a plurality of pairs of natural frequencies and wavenumbers that lie on a model of transverse vibration noise as peaks of the Fourier transform; and

setting a linear system of equations with the at least two physical properties as unknowns.

17. The method of claim 16, wherein tension is known and the at least two physical properties are bending stiffness and density.

18. The method of claim 17, wherein the at least two physical properties are determined by using least-squares inversion.

19. The method of claim 16, wherein density is known and the at least two physical properties are tension and bending stiffness.

20. The method of claim 19, wherein the at least two physical properties are determined by using least-squares inversion.

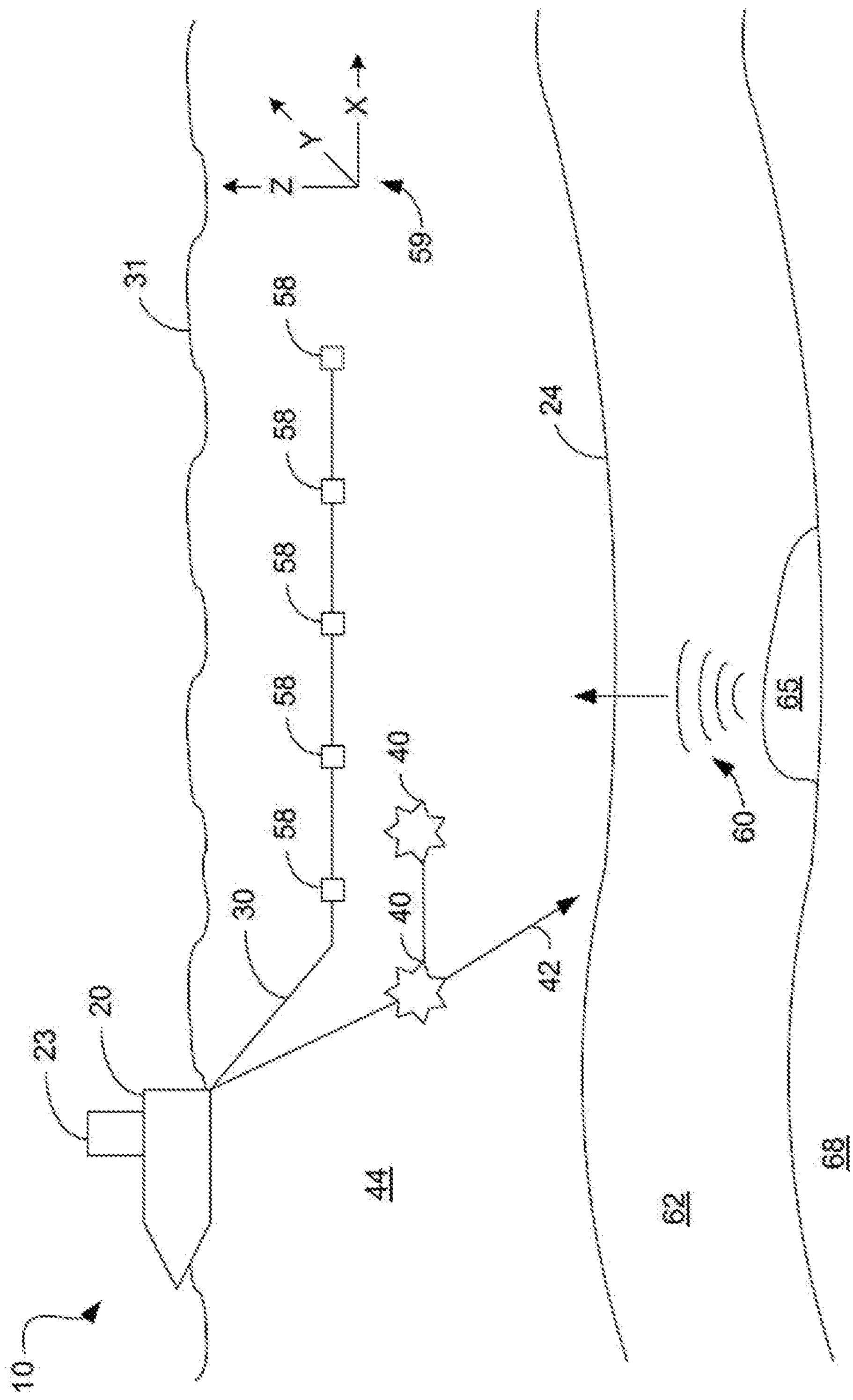

Figure 1

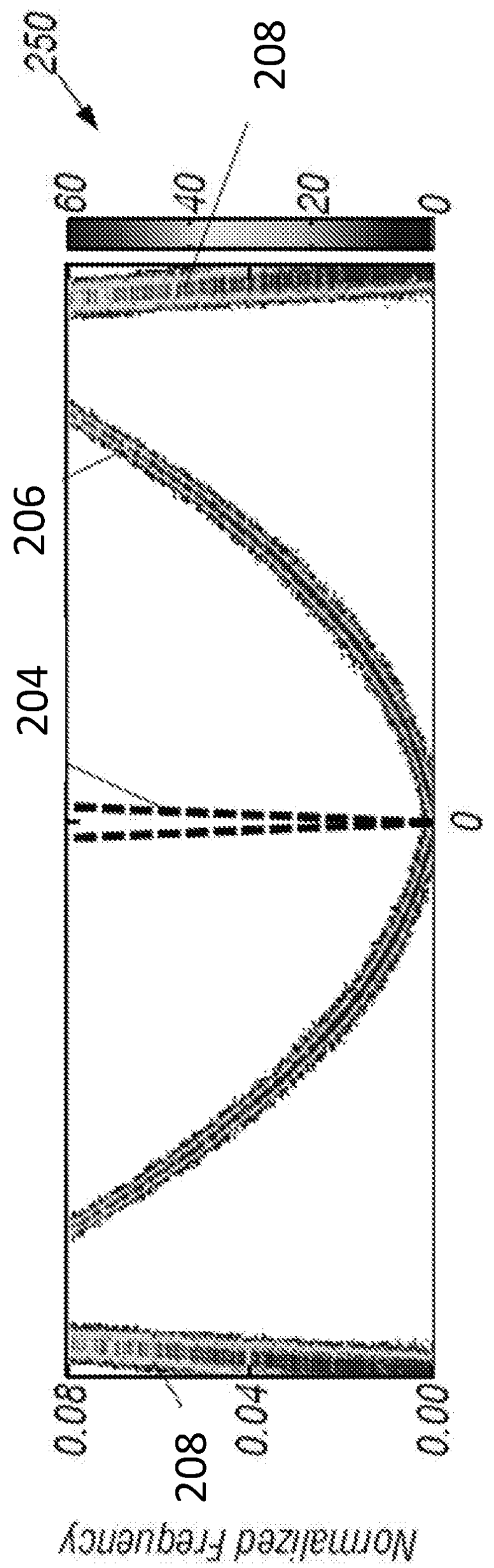
250
208
206
204
60
40
20
0
0
0.08
0.04
0.00
208
Normalized Frequency

Figure 2

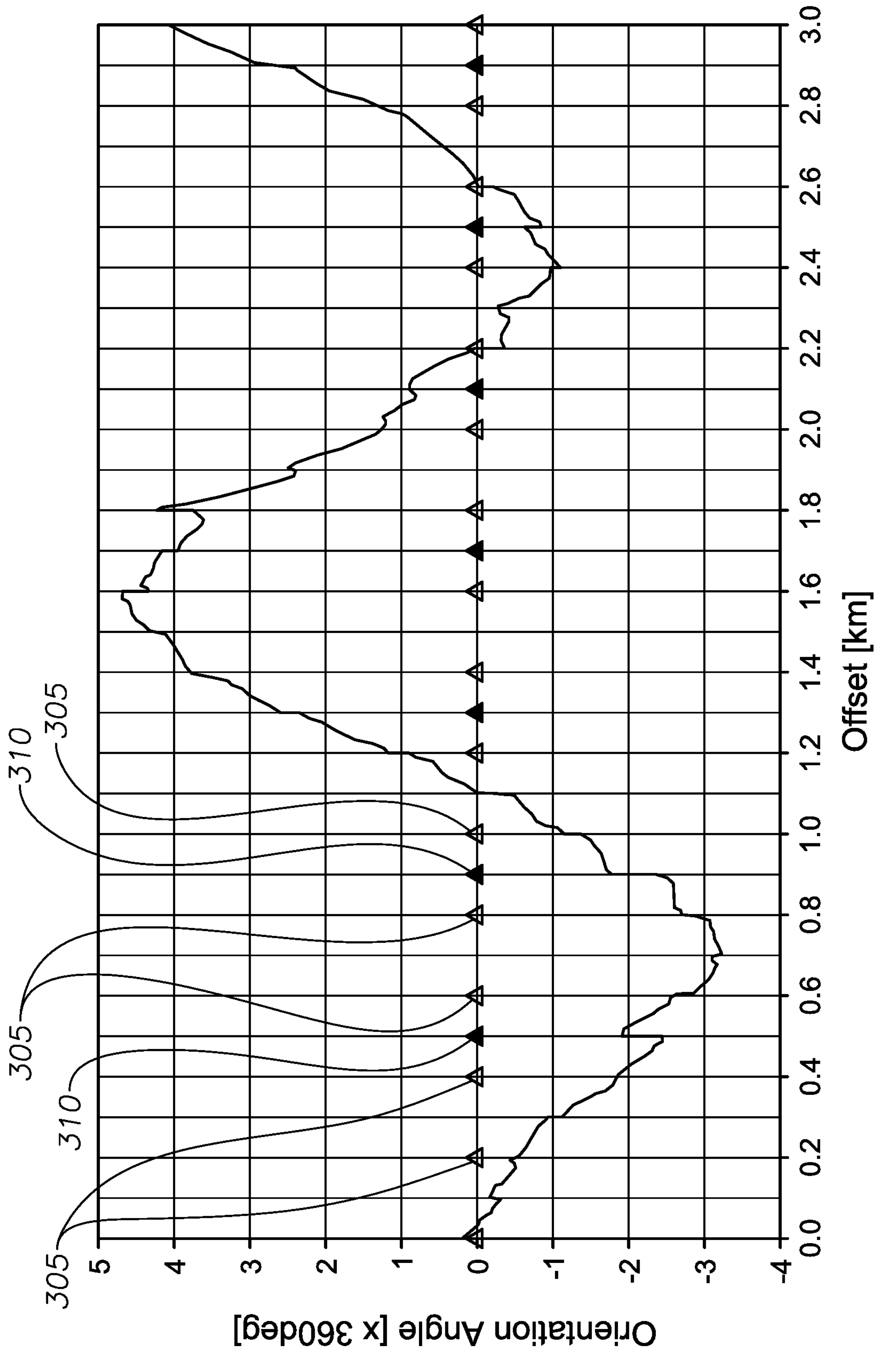
Orientation Angle [x 360deg]
Offset [km]
5
4
3
2
1
0
-1
-2
-3
-4
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.2
2.4
2.6
2.8
3.0
305
310
305
310
305

FIG. 3

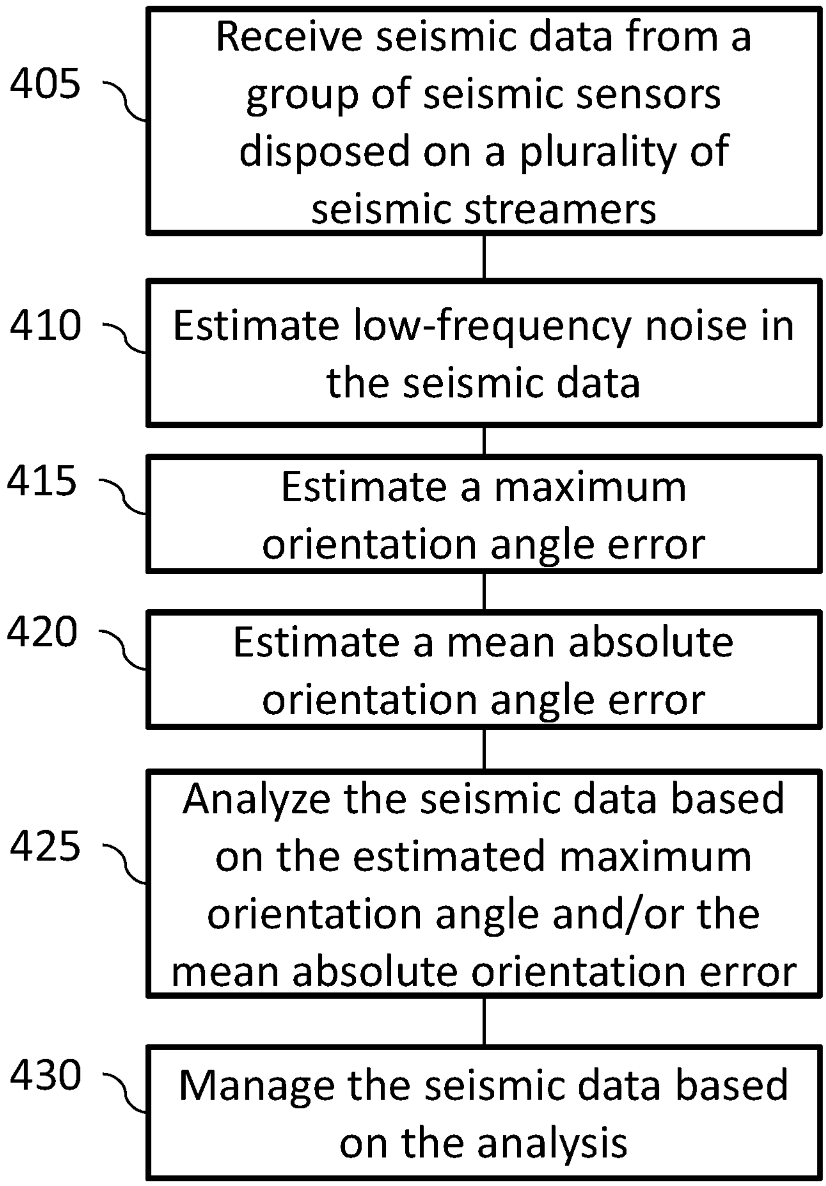
405
Receive seismic data from a group of seismic sensors disposed on a plurality of seismic streamers
410
Estimate low-frequency noise in the seismic data
415
Estimate a maximum orientation angle error
420
Estimate a mean absolute orientation angle error
425
Analyze the seismic data based on the estimated maximum orientation angle and/or the mean absolute orientation error
430
Manage the seismic data based on the analysis

Figure 4

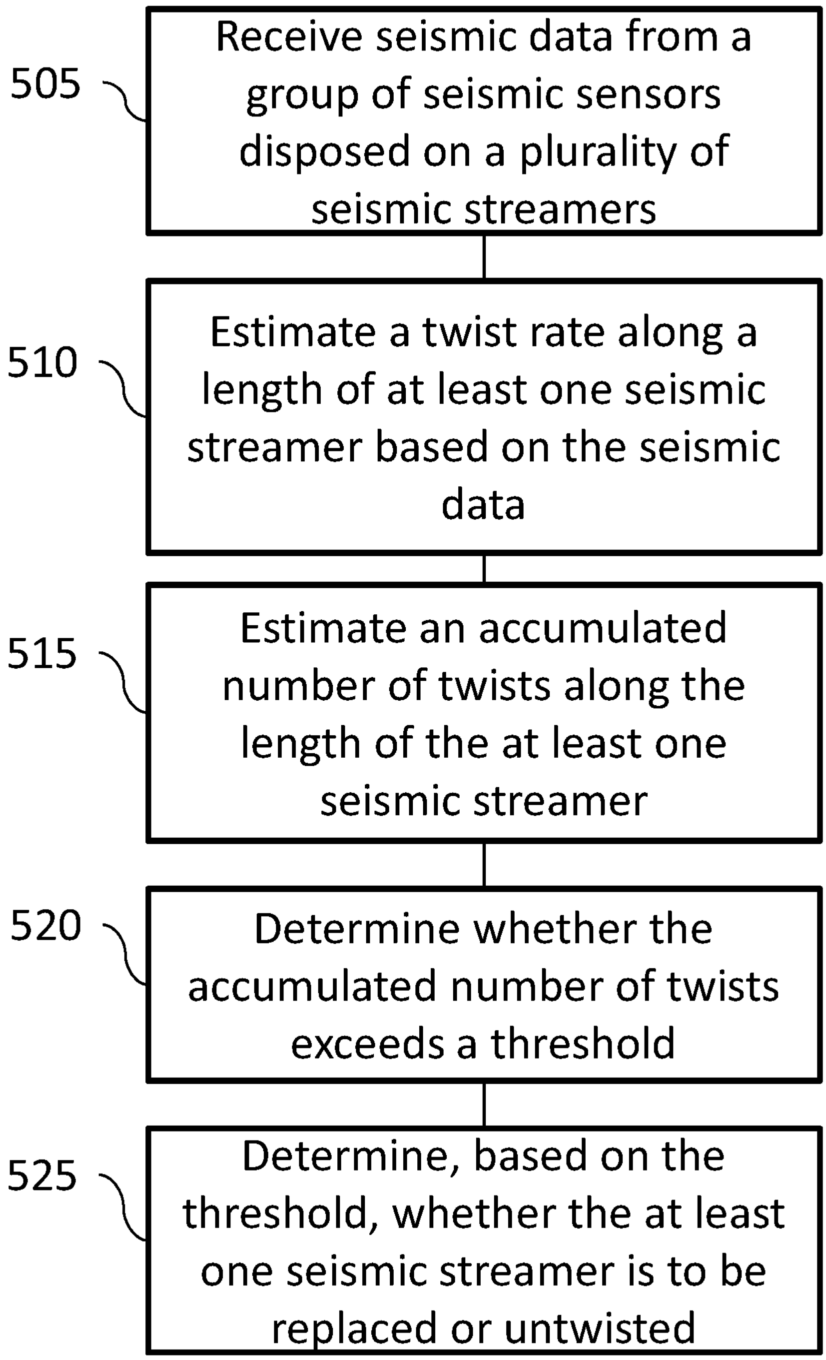
505
Receive seismic data from a group of seismic sensors disposed on a plurality of seismic streamers
510
Estimate a twist rate along a length of at least one seismic streamer based on the seismic data
515
Estimate an accumulated number of twists along the length of the at least one seismic streamer
520
Determine whether the accumulated number of twists exceeds a threshold
525
Determine, based on the threshold, whether the at least one seismic streamer is to be replaced or untwisted

Figure 5

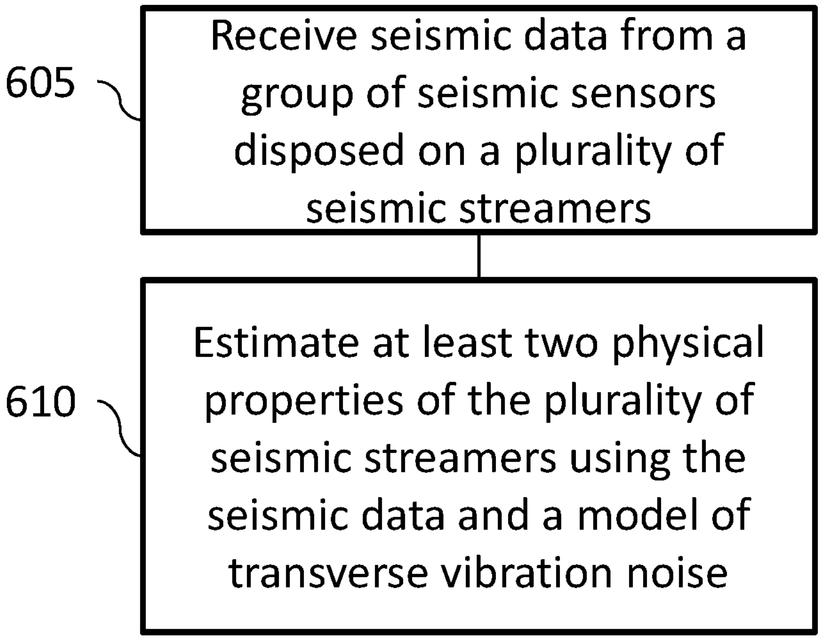
605
Receive seismic data from a group of seismic sensors disposed on a plurality of seismic streamers
610
Estimate at least two physical properties of the plurality of seismic streamers using the seismic data and a model of transverse vibration noise

Figure 6

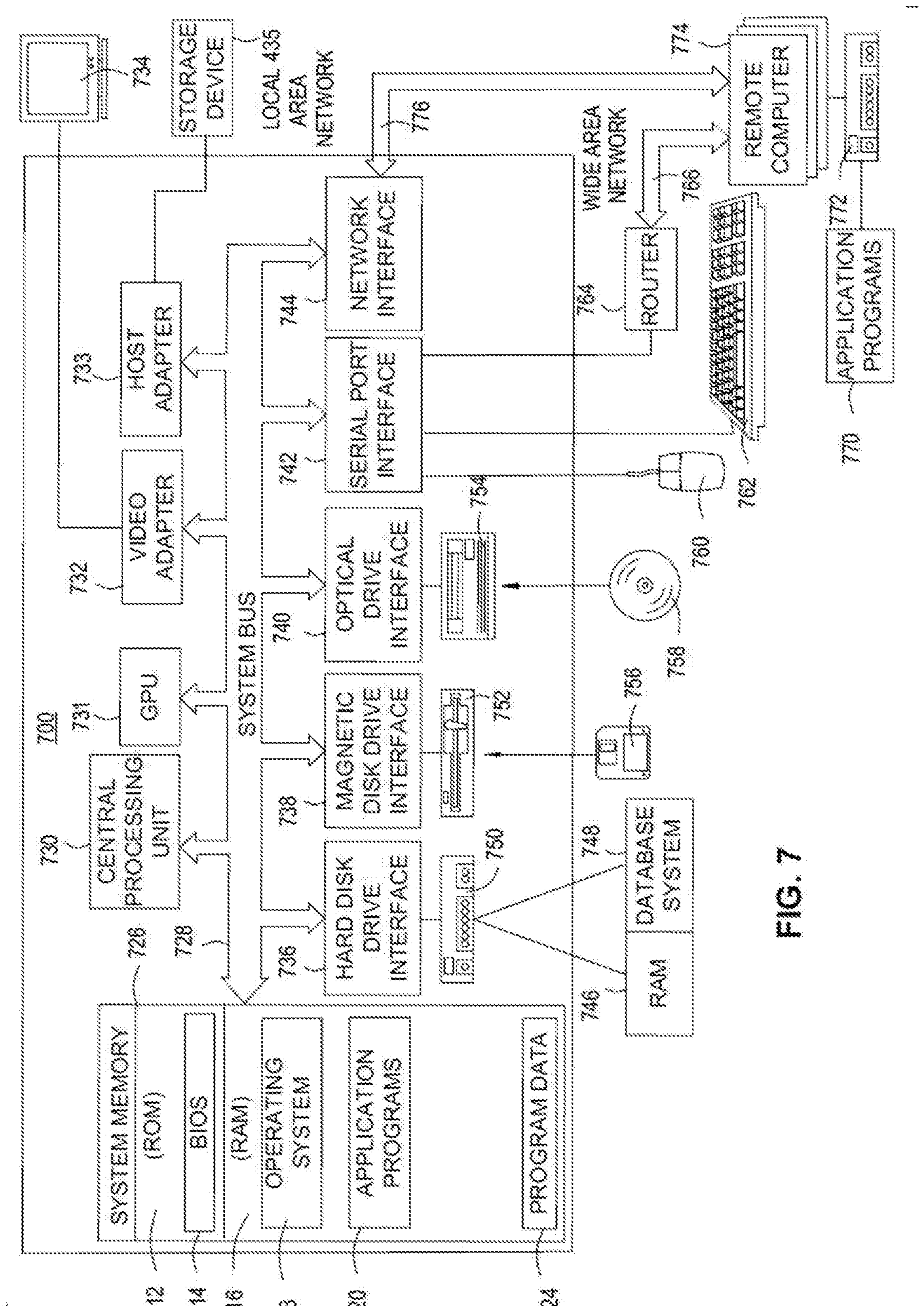
700
SYSTEM MEMORY
(ROM)
BIOS
(RAM)
OPERATING SYSTEM
APPLICATION PROGRAMS
PROGRAM DATA
712
714
716
718
720
724
726
728
CENTRAL PROCESSING UNIT
730
GPU
731
VIDEO ADAPTER
732
HOST ADAPTER
733
734
STORAGE DEVICE
435
LOCAL AREA NETWORK
SYSTEM BUS
HARD DISK DRIVE INTERFACE
736
MAGNETIC DISK DRIVE INTERFACE
738
OPTICAL DRIVE INTERFACE
740
SERIAL PORT INTERFACE
742
NETWORK INTERFACE
744
RAM
746
DATABASE SYSTEM
748
750
752
754
756
758
760
762
ROUTER
764
WIDE AREA NETWORK
766
APPLICATION PROGRAMS
770
772
REMOTE COMPUTER
774
776

FIG. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/013713

A. CLASSIFICATION OF SUBJECT MATTER

G01V 1/30(2006.01)i, G01V 1/38(2006.01)i, G01V 1/20(2006.01)i, G01V 1/09(2006.01)i

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 1/30; G01V 1/38; G01V 1/46; G01V 1/48; G01V 1/36; G01V 1/20; G01V 1/09

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: orientation, angle, seismic, sensor, streamer, frequency, noise, amplitude, survey, control

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2013-0028050 A1 (OZDEMIR et al.) 31 January 2013 See paragraphs [0004], [0015]-[0020], [0032]-[0039], [0052]-[0063]; and figures 1, 3A-3C, 4A-4B, 7.	1-2,4-20
Y		3
Y	US 2012-0082001 A1 (WELKER et al.) 05 April 2012 See paragraph [0025]; and figures 3A-3B.	3
A	US 2008-0025146 A1 (WELKER, KENNETH E.) 31 January 2008 See paragraphs [0032]-[0034], [0036]; and figures 1, 5.	1-20
A	WO 2010-093557 A2 (GECO TECHNOLOGY B.V. et al.) 19 August 2010 See paragraphs [0016]-[0023], [0027]-[0029]; and figures 1, 3-5.	1-20
A	US 2009-0161487 A1 (KJELLGREN et al.) 25 June 2009 See paragraphs [0017]-[0024], [0030], [0040]; and figures 1-2, 6.	1-20

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"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
25 April 2016 (25.04.2016)

Date of mailing of the international search report
25 April 2016 (25.04.2016)

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		WO 2012-044479 A3	07/06/2012
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		WO 2010-093557 A3	18/11/2010
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