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GB 2591098 B

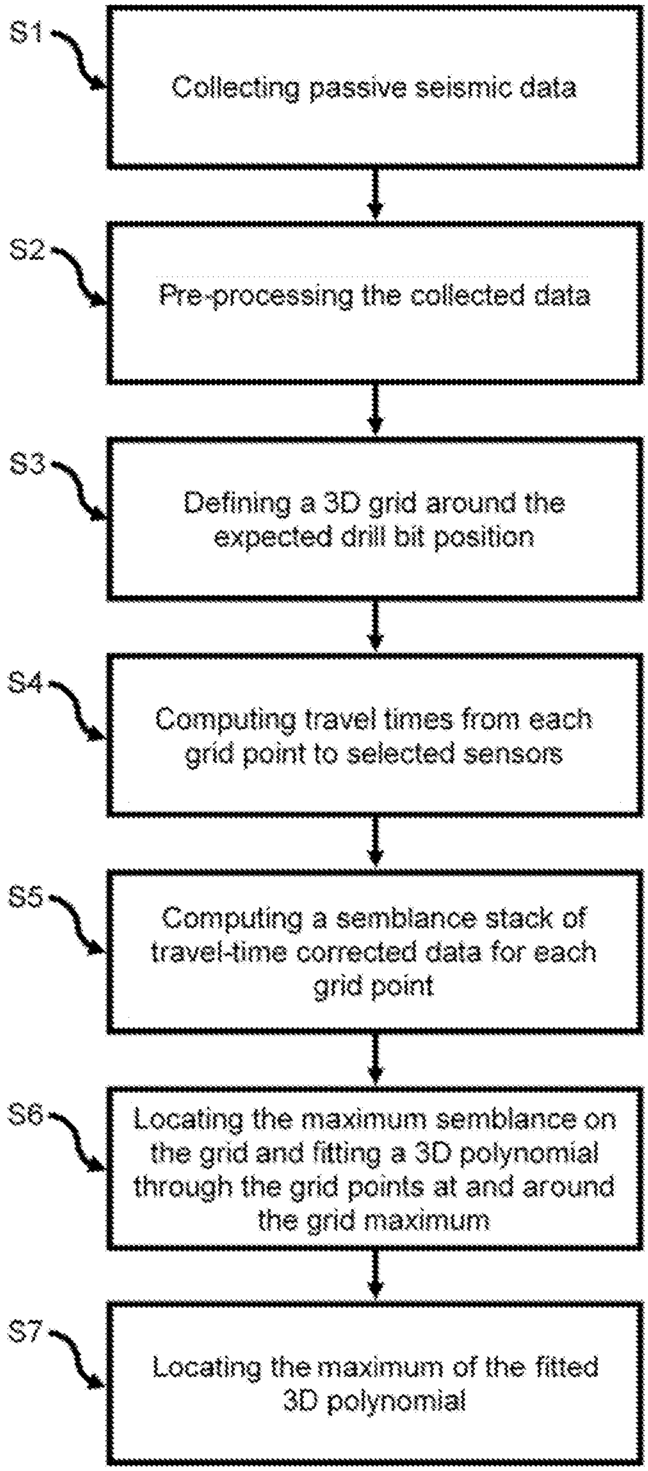

S1
Collecting passive seismic data
S2
Pre-processing the collected data
S3
Defining a 3D grid around the expected drill bit position
S4
Computing travel times from each grid point to selected sensors
S5
Computing a semblance stack of travel-time corrected data for each grid point
S6
Locating the maximum semblance on the grid and fitting a 3D polynomial through the grid points at and around the grid maximum
S7
Locating the maximum of the fitted 3D polynomial

Figure 1

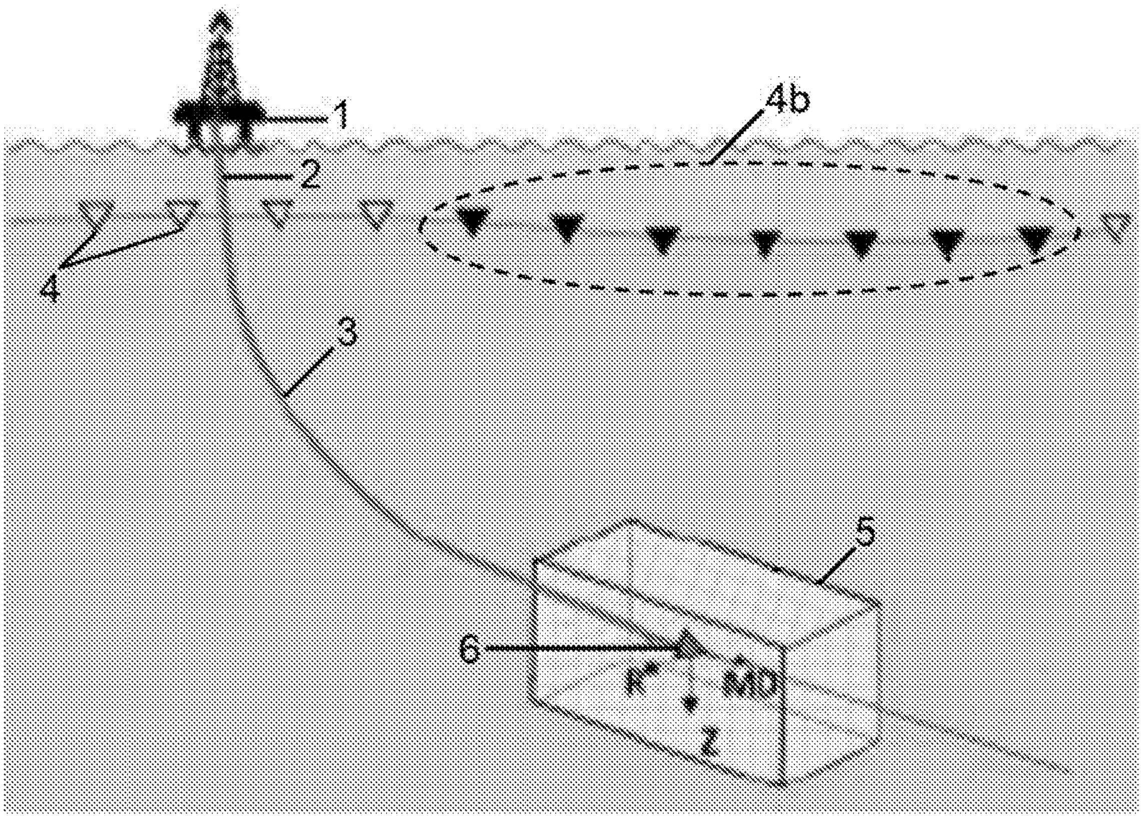


Figure 2

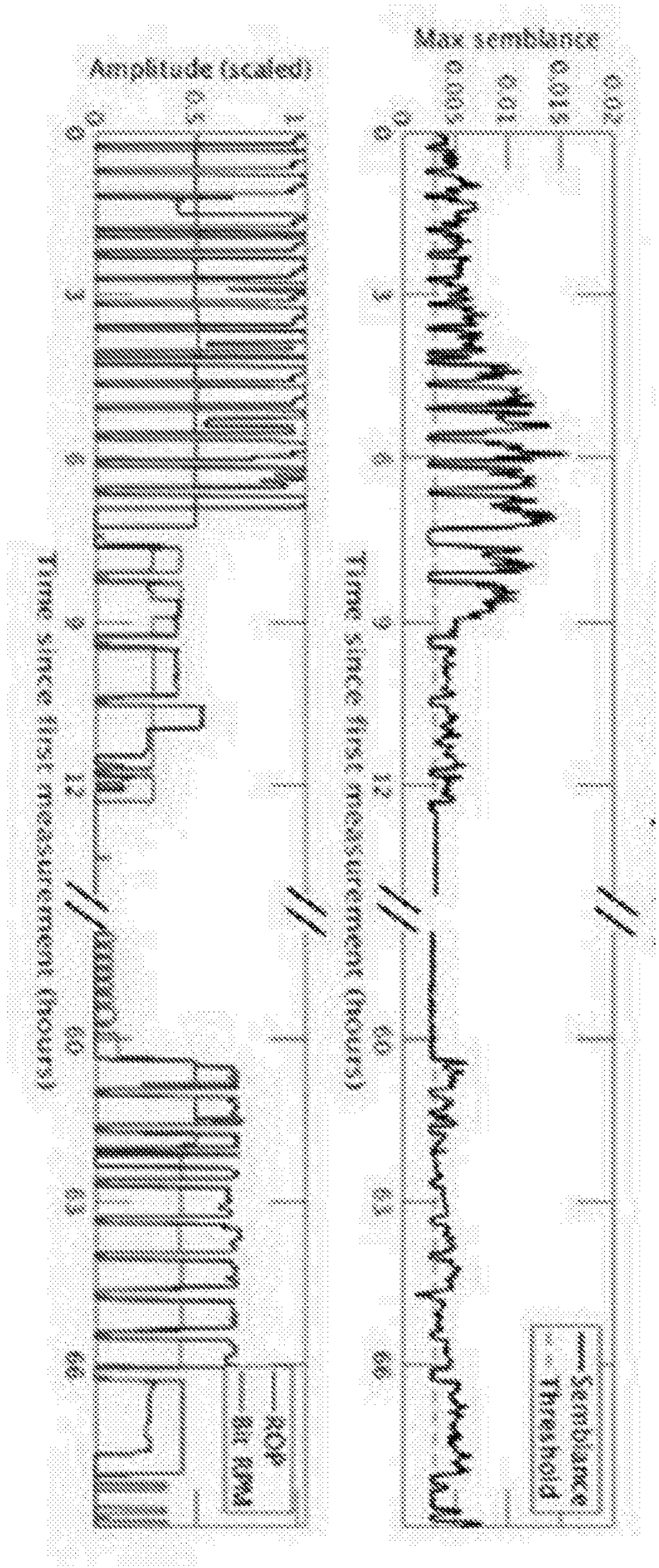
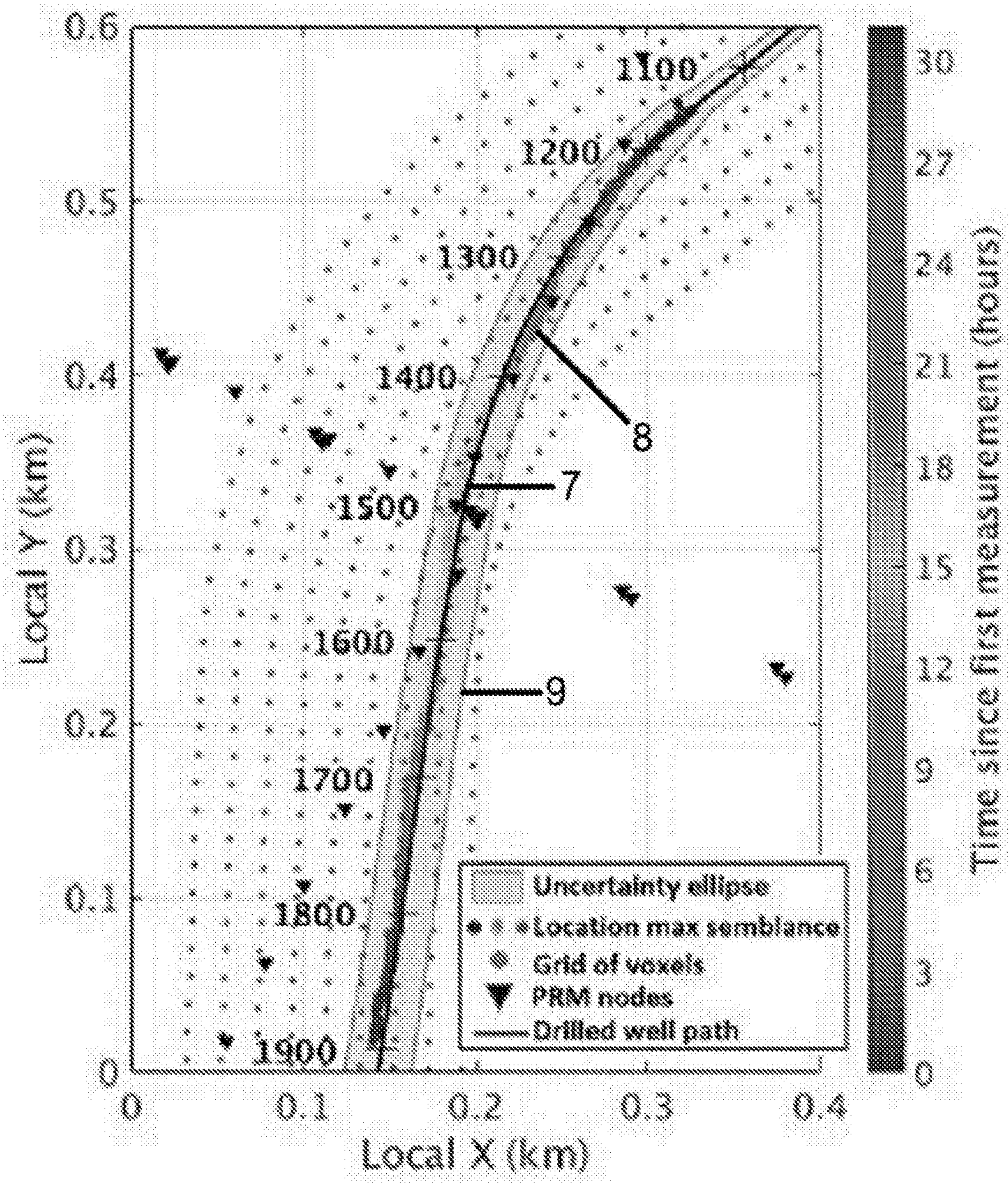

Amplitude (scaled)
Max semblance
Time since first measurement (hours)
Time since first measurement (hours)
ROP
Bit RPM
Semblance
Threshold

Figure 3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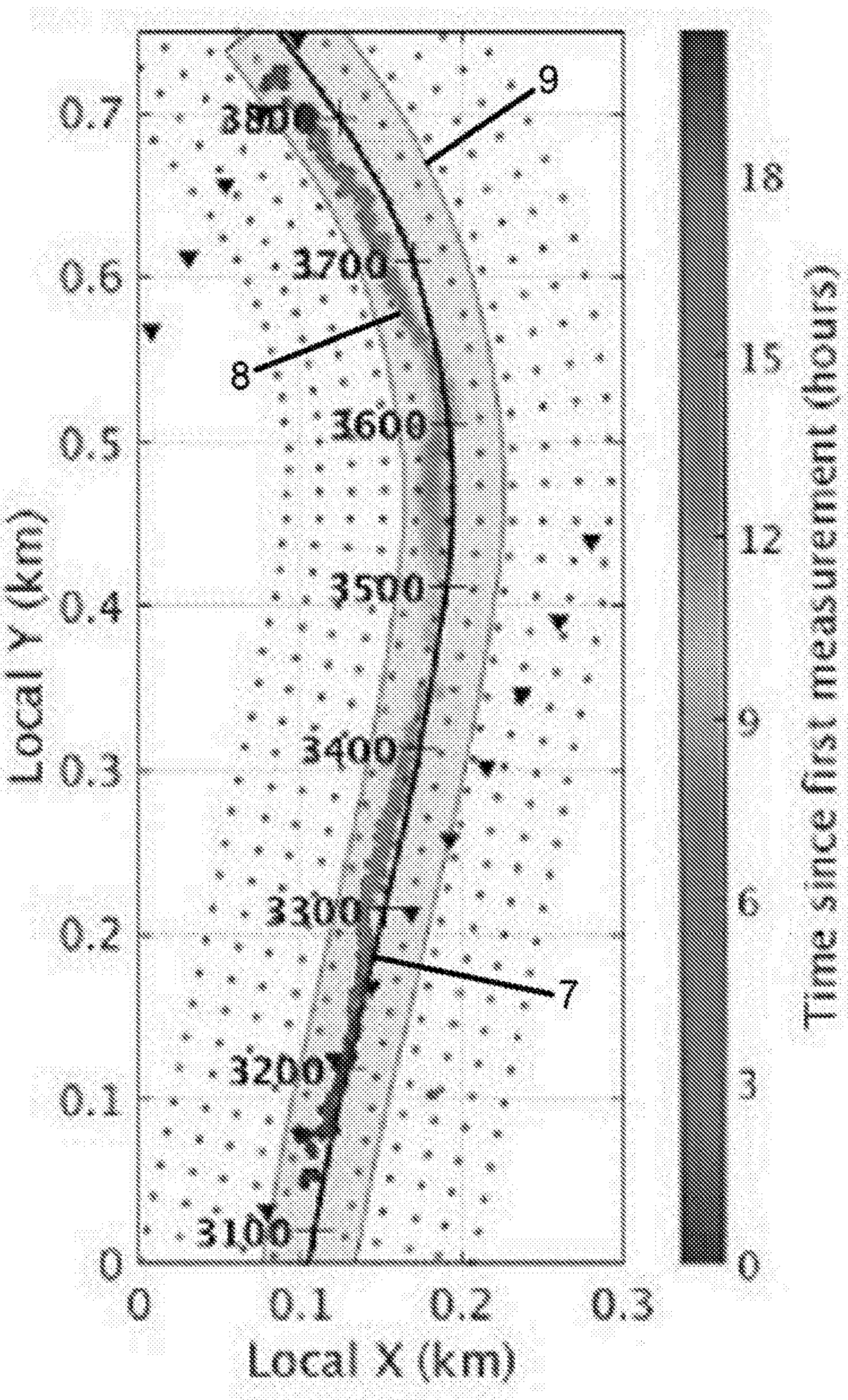
0.5
0.4
0.3
0.2
0.1
0
Local Y (km)
0
0.1
0.2
0.3
0.4
Local X (km)
1100
1200
1300
1400
1500
1600
1700
1800
1900
8
7
9
Uncertainty ellipse
Location max semblance
Grid of voxels
PRM nodes
Drilled well path
30
27
24
21
18
15
12
9
6
3
0
Time since first measurement (hours)

Figure 4



3800
3700
3600
3500
3400
3300
3200
3100
9
8
7
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0.1
0.2
0.3
Local Y (km)
Local X (km)
18
15
12
9
6
3
0
Time since first measurement (hours)

Figure 5

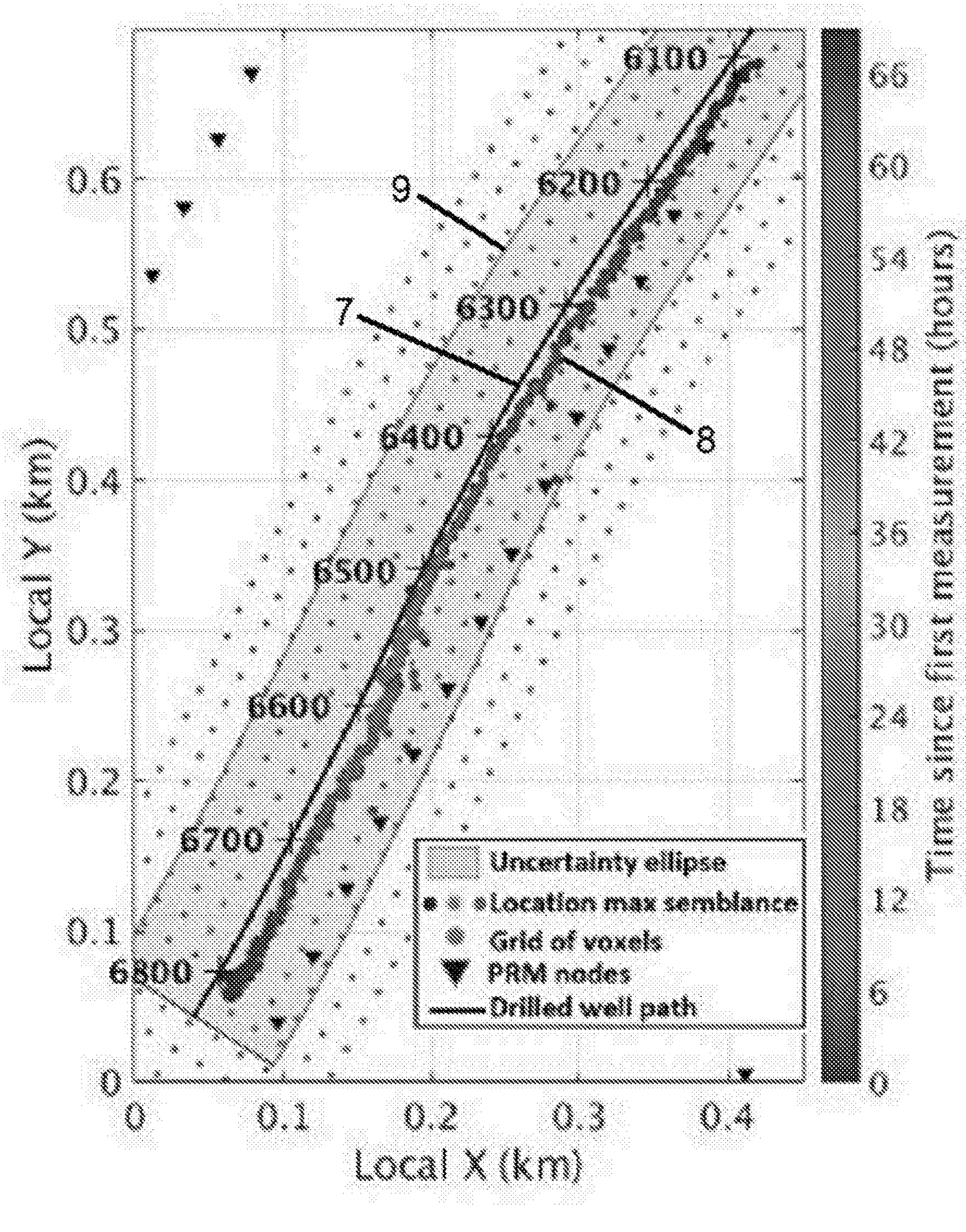

6100
6200
6300
6400
6500
6600
6700
6800
9
7
8
Uncertainty ellipse
Location max semblance
Grid of voxels
PRM nodes
Drilled well path
Local Y (km)
Local X (km)
Time since first measurement (hours)
0
0.1
0.2
0.3
0.4
0.5
0.6
0
0.1
0.2
0.3
0.4
0
6
12
18
24
30
36
42
48
54
60
66

Figure 6

SUB-SURFACE WELL LOCATION DETERMINATION

Technical field

The present invention relates to the field of sub-surface well location determination, either during drilling of the well or subsequent to drilling completion.

Background

Conventionally, the position of a well is derived from magnetic and/or gyroscopic measurements made while drilling (MWD). The error associated with these measurements accumulates with lateral distance away from the well head, and can become relatively large, especially for long horizontal wells. As a result, measurements for long horizontal wells have large lateral positional uncertainty, for example ± 60m at 6000m measured depth (MD, i.e. length along the well path). Reducing this uncertainty is important, particularly as new infill wells may be drilled at 50-75m lateral distance from existing wells.

It is known (Katz, 1984, Poletto and Miranda, 2004) to estimate the position of a drill bit whilst drilling a well by detecting seismic signals, generated by the drill bit, using an array of seismic sensors located on the surface, or in or on water in the case of a subsea well. This seismic data recorded in the absence of a controlled (time-synchronized) seismic source is referred to as "passive" seismic data.

Summary of the invention

According to an aspect of the present invention there is provided a method of estimating the current position of a drill bit or other noise source within a subsurface formation of the Earth. The method comprises the following steps: a) collecting seismic data from a plurality of seismic sensors spread across a region of the surface of the Earth above the drill bit or other noise source and / or located in one or more nearby wells; b) pre-processing the seismic data to enhance a contribution of drill bit or noise source generated noise; c) defining a set of points on a grid in 3-dimensional space that includes an expected position of the drill bit or noise source; d) computing travel times for seismic waves from each said point to each seismic sensor location; e) for each said point, using the pre-processed seismic data, sensor location data, and computed travel times to compute a semblance stack of travel-time corrected seismic data in a time window; f) determining the grid location of the maximum semblance and fitting a 3-dimensional function around this grid location; and g) identifying the location of a maximum of the 3-dimensional function and using that as an estimate of the current position of the drill bit or other noise source.

The three dimensional function may be a second degree polynomial.

Steps a) to g) may be repeated for consecutive time windows to obtain an estimate of a well position and trajectory. The time windows may be overlapping or may be spaced apart in time.

The method may comprise passing a noise source along a pre-existing well to obtain an estimate of the well position and trajectory of the well.

The method may comprise drilling a new well with a drill bit of a drilling assembly.

The plurality of seismic sensors may be sensors of a permanent reservoir monitoring array and/or a temporary deployed array at the seabed, and/or downhole sensors in wells.

The plurality of seismic sensors may comprise conventional 4D sensors and / or fiber-optic DAS cables.

The pre-processing may comprise the use of a bandpass filter, an FX median filter, PZ-summation, and a subspace filter.

The time window may be between 20 and 120 seconds in duration.

Step g) may further comprise additionally identifying a value of said maximum and using that to determine a noise level at said drill bit or other noise source.

Preferred embodiments of the invention will now be described, by way of example only, with reference to the accompanying drawings.

Brief description of the drawings

Figure 1 is a flow diagram which illustrates the general steps of a sub-surface well location determination method;

Figure 2 illustrates schematically a procedure for estimating the position of a drill bit whilst drilling a subsea well;

Figure 3 shows, for an exemplary well, the observed maximum semblance value and the rate of penetration (ROP) and rotations per minute (RPM) of the drill bit as a function of time.

Figure 4 shows the maximum semblance position for an exemplary well at a measured depth of approximately 1500m.

Figure 5 shows the maximum semblance position for an exemplary well at a measured depth of approximately 3500m.

Figure 6 shows maximum semblance position for an exemplary well at a measured depth of approximately 6500m.

Detailed description

A method of estimating the current position of a drill bit or other noise source within the drill string or bottom hole assembly (BHA) or in a subsurface formation of the Earth is described below. The proposed method tracks noise from drilling operations or other noise sources within passive seismic data. The data is analysed to obtain independent measurements of a well position, which do not suffer from an accumulation of error with measured depth. This allows the well path to be localized laterally with a higher accuracy than can be obtained with conventional gyroscopic and magnetic measurements. For a horizontal well 6500m in length for example, the lateral positional uncertainty of the well path may be reduced from over 60m to approximately 15m. The proposed method supports improved well placement by reducing the lateral position uncertainty while drilling, in real time. The risk of adverse events, e.g. drilling infill wells too close to already existing producers, may also be reduced.

Permanently-deployed reservoir monitoring (PRM) arrays provide continuous background noise recordings, amounting to Terabytes of passive seismic data every day. Passive data can, therefore, be measured using an existing PRM system. Hence for PRM-equipped fields, the method provides accurate, complementary information at minimal extra costs, for real-time well positioning that can be used for decision making during drilling operations.

The present method is based on computing, using a known semblance analysis technique, the semblance stack of passive seismic data. The stack is computed along travel time curves from each grid point in a subsurface volume to selected seismic sensors at the seabed (or land surface). The method can also be used for detecting sudden, transient drilling issues (e.g. liner failure) and drilling-induced events in the analysed subsurface volume.

Figure 1 is a flow diagram illustrating the general steps of the sub-surface well location determination method. The method comprises the steps of:

S1) Collecting passive seismic data;

S2) Pre-processing the collected data;

S3) Defining a 3D grid around the expected drill bit position;

S4) Computing travel times from each grid point to selected sensors;

S5) Computing a semblance stack of travel-time corrected data for each grid point;

S6) Locating the maximum semblance on the grid and fitting a 3D polynomial through the grid points at and around the grid maximum; and

S7) Locating the maximum of the fitted 3D polynomial.

This method is further illustrated in Figure 2, which shows an offshore drilling platform 1, with a drill string 2 extending from the platform into a well 3 extending through the subsurface formation.

In S1, sensors 4, which may be part of an existing permanently-deployed reservoir monitoring (PRM) array, are used to collect passive seismic data. Such an array may be primarily used, in a known way, for periodic 4D seismic monitoring of a reservoir and the overburden. A known system has been developed, for example, to use passively monitored seismic data for detecting and locating microseismic events induced by injection into wells (Bussat et al., 2016, Bussat et al., 2018) to support safe operations and prevent out-of-zone injection. The sensors 4 may be of a conventional or fibre-optic distributed acoustic sensing (DAS) type. This known PRM array, and the data it provides, is used in a new way to track the well location.

Typically, for periodic microseismic monitoring by semblance analysis, a temporal semblance window is defined. Passive data collected with the sensors is processed and stacked over the sensors and the semblance window for semblance analysis. In the present case, since the drilling operation is expected to produce a continuous signal, a longer semblance window is used compared to that used for conventional microseismic monitoring. The window should be sufficiently long to be able to pick up the continuous but rather weak drilling noise, but sufficiently short such that the drill bit does not move substantially, which would cause the image of the noise source to be blurred. An example of a suitable semblance window is in the range of 20 to 120 seconds in duration depending on drilling parameters, for example 90 seconds to scan through the passive data.

As well as the noise from the drill bit, the passive seismic data contains noise from a range of different sources that are not of interest for the positional monitoring, such as interference from nearby seismic acquisitions, noise from the platform, and noise from vessels in the neighbourhood. To be able to track the drilling noise therefore, the passive data is pre-processed after collection (S2). This may be achieved by the use of a bandpass filter, an FX median filter, PZ-summation, and a subspace filter prior to computing the semblance. Except for the bandpass filter, the filters are data-driven; that is, filter parameters are computed continuously during operation. The parameters for these filters can, therefore, be optimized for the noise present in the data at any given time. By appropriate pre-processing, a significant amount of background noise is removed from the passive data.

For each time interval corresponding to the semblance window length, a processing grid 5 that covers a limited monitoring volume around the current expected drill bit position 6 is then defined (S3), as shown in Figure 2. The method by which the initial expected position is obtained is not limited, although this may be known from the well-planning phase in combination with the current length of the drill string. Conventional magnetic MWD or gyroscopic techniques may be used to estimate the drill bit position more accurately. The estimate may then be stored in a database, along with real-time drilling parameters such as rate of penetration (ROP) and bit rotations per minute (RPM). The expected position is fetched for the construction of the processing grid. The spatial extent of the monitoring volume should be large enough to cover possible revisions of the planned well path, and the grid spacing can be relatively coarse. For example, the extension of the volume may be ± 200m along the well path (MD axis) with 20m grid spacing, and ± 80m laterally (R axis) and 140m vertically (Z axis) away from the well path with 20 and 35m grid spacing, respectively.

P-wave travel times between the sensors 4 and all points on the processing grid are then obtained (S4), for example by ray tracing or wavefield modelling through a velocity model. For this step, an optimal subset 4b of the available PRM nodes may be selected and used for a given expected drill bit position. The selected nodes may be, for example, all nodes within an area centred above the drill bit with a radius equal to the current vertical depth of the drill bit. By reducing the amount of data for analysis, both in terms of the number of sensors and in terms of the number of grid points on the processing grid, the amount of computational power and computational time required for processing is reduced. The travel times are then used to travel time-correct the seismic data (the vertical component of the geophone after pre-processing). For each grid point on the processing grid, the traveltime-corrected data from the selected nodes are then stacked to compute the semblance by known methods (S5). This procedure may be repeated for consecutive semblance windows, whether or not partially overlapping, with a potentially new optimal subset of receivers.

The location and value of the maximum semblance on the processing grid is then determined (S6). The finer the grid, the higher the positional precision achieved. A finer grid, however, requires higher computational power and longer computational time. Therefore, to obtain sub-grid resolution, in particular when using a relatively coarse processing grid, the exact location of the maximum semblance and its value may be estimated by fitting a second-degree polynomial in 3D through the 3x3x3 grid points around the grid maximum. A coarse grid used in combination with this 3D fitting gives very similar results to a finer grid, and is much faster to compute. This is an important benefit for real-time implementation and positional decision-making.

The resulting estimates (fitted maximum semblance position and value) may then be stored in a database, together with the median semblance value on the grid to represent the background noise level. When the estimated location in any direction is far from the maximum semblance on the grid, it is a sign of low-quality data without a clear maximum in the semblance volume. For example, when the estimated location in any direction is farther than one grid point away from the grid point with maximum semblance. Any such observations may be flagged as 'bad data' and replaced with their original maximum value and location on the grid. The value of the fitted maximum semblance, or, if replaced in case of bad data, the original grid maximum, may be used as a measure of the amount of noise detected from the drilling operation. The position of the maximum of the 3-dimensional polynomial or, if replaced in the case of bad data, the original grid position of the maximum, may be used as the estimate for the location of the noise source, i.e. the current position of the drill bit or other noise source in the BHA (S7).

Figure 3 shows results collected from an exemplary well, where a bandpass filter, an FX median filter, PZ-summation, and a subspace filter have been applied to the passive data. The lower panel shows the rate of penetration (ROP) (upper trace) and rotations per minute (RPM) (lower trace) of the drill bit as a function of time. The upper panel shows the observed maximum semblance value, also as a function of time. The data for both panels is aligned along a common time scale for comparison. There is a clear correlation between maximum semblance and drill bit activity. When the drill bit is rotating and advancing (ROP >0), the semblance is high, while the semblance is low when drilling is paused (these low semblance values are typically flagged as bad data). This confirms that the detected noise comes from the drilling operation, and the pre-processing preserves the drilling noise.

Figures 4-6 show results of the maximum semblance positions obtained for three wells (at approximately 1500, 3500, and 6500m along the length of the well path respectively) after carrying out the method as described. Each of the figures shows a map view of the estimated drilled well path 7 and corresponding 95% uncertainty ellipse 9 from gyroscopic measurements. The fitted location of the maximum semblance 8 for 90 second intervals of data, the grid points at which the semblance is computed, and the PRM nodes, are plotted. Threshold values for the semblance and signal-to-noise ratio (SNR) (represented by maximum divided by median semblance) and the 'bad data'-flag are used to filter measurements before plotting. Over time, the observations are located at increasing measured depth (length along well path), following the progress of the drilling.

Figures 4-6 show that the lateral extent of the error ellipse 9 for the gyroscopic measurements for horizontal wells increases from less than 10-15m at around 1500 m measured depth (Figure 4) to over 60m at 6500 m measured depth (Figure 6). The position of the (filtered) maximum semblance 8 obtained by the method described above is close to the drilled well path 7, as estimated by gyroscopic measurements, and well within the corresponding uncertainty ellipse. The lateral spread of the observations, however, shown by the spread of the region 8, is far smaller than the width of the error ellipse for the gyroscopic measurements, and is independent of measured depth (that is, independent of the position along the well path). This indicates that the passive data can be used to reduce the lateral well positional uncertainty significantly, by approximately a factor 4 for a 6500m long well, compared to the gyroscopic measurements. The reduction in uncertainty may be even higher during favourable (quiet) ambient noise conditions.

Instead of the drill bit, any other suitable source may be used to produce the noise used for localisation. For example, an acoustic source may be gradually lowered into an already drilled well whilst generating noise. Such alternative noise sources may be introduced to the well bore alone, or they may be introduced by equipment to be used for other downhole operations, for example cement bond logging tools. In this way, the cost of operation would be reduced. Furthermore, additional noise sources may be used simultaneously with a drill bit. This may, for example, be used to supplement the noise produced by the drill bit during operation, and could be useful in situations where the noise reaching the surface sensors from the drill bit itself is weak or insufficient for proper localisation.

Instead of a permanently-deployed PRM system, the method can also be used with temporarily deployed cables. This method may be also used to provide depth estimates for the noise source. Depth estimates may be improved by including passive data from sensors (conventional sensors or a fiber-optic DAS systems) which are located downhole in the same or one or more nearby wells as well as from those at the surface. It is further noted that, by reducing the semblance window length, this method may also be used to detect sudden, transient, drilling-related events.

CLAIMS:

1. A method of estimating the current position of a drill bit or other noise source within a subsurface formation of the Earth, the method comprising:

a) collecting seismic data from a plurality of seismic sensors spread across a region of the surface of the Earth above the drill bit or other noise source and / or located in one or more nearby wells;

b) pre-processing the seismic data to enhance a contribution of drill bit or noise source generated noise;

c) defining a set of points on a grid in 3-dimensional space that includes an expected position of the drill bit or noise source;

d) computing travel times for seismic waves from each said point to each seismic sensor location;

e) for each said point, using the pre-processed seismic data, sensor location data, and computed travel times to compute a semblance stack of travel-time corrected seismic data in a time window;

f) determining the grid location of the maximum semblance and fitting a 3-dimensional function around this grid location; and

g) identifying the location of a maximum of the 3-dimensional function and using that as an estimate of the current position of the drill bit or other noise source.

2. A method according to claim 1 and comprising:

repeating steps a) to g) for consecutive time windows to obtain an estimate of a well position and trajectory.

3. A method according to claim 2, and comprising passing a noise source along a pre-existing well to obtain an estimate of the well position and trajectory of the well.

4. A method according to claim 2 and comprising drilling a new well with a drill bit of a drilling assembly.

5. A method according to any one of the preceding claims, wherein said plurality of seismic sensors are sensors of a permanent reservoir monitoring array and/or a temporary deployed array at the seabed, and/or downhole sensors in wells.

6. A method according to any one of the preceding claims, wherein said plurality of seismic sensors comprise conventional 4D sensors and / or fiber-optic DAS cables.

7. A method according to any one of the preceding claims, wherein said pre-processing comprises the use of a bandpass filter, an FX median filter, PZ-summation, and a subspace filter.

8. A method according to any one of the preceding claims, wherein said time window is between 20 and 120 seconds in duration

9. A method according to any one of the preceding claims, wherein step g) further comprises additionally identifying a value of said maximum and using that to determine a noise level at said drill bit or other noise source.

10. A method according to any one of the preceding claims, wherein said three dimensional function is a second degree polynomial.