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[Continued on next page]

(54) Title: METHOD TO LOOK AHEAD OF THE BIT

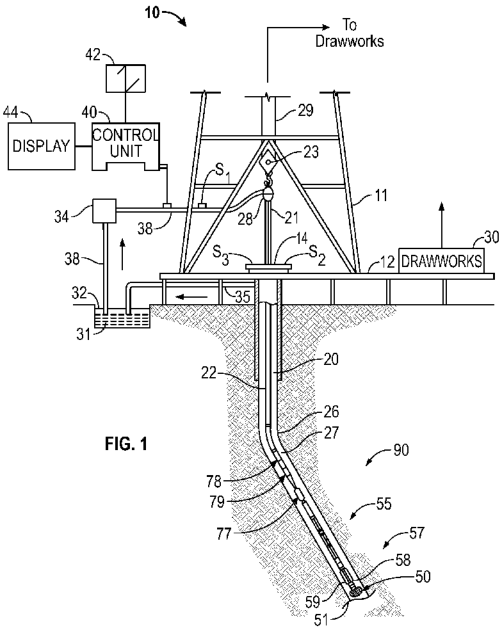

FIG. 1

(57) Abstract: The present disclosure is direct to method of performing measurements while drilling in an earth formation. The method may include estimating a location of a seismic reflector using signals from one or more of seismic sensors located at a plurality of locations in a borehole and the drilling depth of the one or more seismic sensors in a borehole. The signals may include information about times when the seismic sensors detect a direct wave and a reflected wave. The method may include storing the information in a memory using a processor.

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TITLE: METHOD TO LOOK AHEAD OF THE BIT

INVENTOR: COMAN, Radu

BACKGROUND OF THE DISCLOSURE

Field of the Disclosure

[0001] The present disclosure relates to a method of locating seismic features in an earth formation.

Description of the Related Art

[0002] Conventional reflection seismology utilizes surface sources and receivers to detect reflections from subsurface impedance contrasts. The obtained image often suffers in spatial accuracy, resolution, and coherence due to the long travel paths between source, reflector, and receiver. In particular, due to the two-way passage of seismic signals through a highly absorptive near surface weathered layer with a low, laterally varying velocity, subsurface images are poor quality. To overcome this difficulty, a technique commonly known as vertical seismic profiling (VSP) was developed to image the subsurface in the vicinity of a borehole. With VSP, a surface seismic source is used and signals are received at a single downhole receiver or an array of downhole receivers. This is repeated for different depths of the receiver (or receiver array). In offset VSP, a plurality of spaced apart sources may be sequentially activated, enabling imaging of a larger range of distances than would be possible with a single source.

[0003] VSP measurements made during drilling operations are referred to as Seismic-while-drilling (SWD®). The signals generated by seismic sources are reproducible and may be stacked. The other kind of data recorded by the seismic sensors is noise. Background noise (drilling noise, circulation noise, rig noise, cultural noise, environmental noise) may be distinguished from spiky noise (e.g. due to hitting the drill string while connection; micro earthquakes close to the borehole). It may be helpful to restrict seismic recording of data to low-noise periods. It may also helpful to stack the data. Because the noise is random, stacking the data may increase the signal to noise ratio.

[0004] The SWD® measurements may include the VSP-while drilling (VSP-WD) method and the checkshot-WD (CS-WD) method. These methods permit updating of the geological model. In this way one can reduce the drilling risk and/or update the optimal well path. The importance of real-time processing is evident, but a full real-time processing isn't possible yet. One limitation of Seismic-while-drilling measurements is the small bandwidth of the uplinks and downlinks. The communication is done via mud telemetry, which is possible only while circulating. Hence when tripping in or tripping out, measurements are done without circulating between shooting windows, and it is not possible to send uplink signals and downlink signals. Even when mud telemetry is possible, the bandwidth available for uplink signals and downlink signals is very small.

[0005] Due to the small uplink bandwidth, the downhole tool must automatically detect and process the shooting sequence(s) downhole. Only the final results (e.g., the first-break time) are sent to the surface.

[0006] Another limitation VSP-WD is the requirement highly accurate clocks (on the order of 1 millisecond time drift per ten day period) that are synchronized for performing measurements. The requirements for high accuracy and synchronization may result in high complexity and cost.

[0007] There is a need for a method of performing seismic measurements that may use less accurate, and hence less complex and less expensive, clocks and synchronization systems. The present disclosure addresses this need.

SUMMARY OF THE DISCLOSURE

[0008] In aspects, the present disclosure is related to systems, devices, and methods of locating seismic features in an earth formation.

[0009] One embodiment according to the present disclosure includes a method of performing measurements while drilling in an earth formation, the method comprising: estimating a location of a seismic reflector using (i) a plurality of signals from at least one seismic sensor, each signal being generated at a unique drilling depth and indicative of a direct wave and a reflected wave, and (ii) the at least one unique drilling depth for the at least one seismic sensor; wherein a time of initiation of the direct wave is indeterminate to a clock associated with the at least one seismic sensor.

[0010] Another embodiment according to the present disclosure includes a non-transitory computer-readable medium product having instructions thereon that, when executed, cause at least one processor to perform a method, the method comprising: estimating a location of a seismic reflector using (i) a plurality of signals from at least one seismic sensor, each signal being generated at a unique drilling depth and indicative of a direct wave and a reflected wave, and (ii) the at least one unique drilling depth for the at least one seismic sensor; wherein a time of initiation of the direct wave is indeterminate to a clock associated with the at least one seismic sensor.

BRIEF DESCRIPTION OF THE DRAWINGS

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

FIG. 1 shows a logging-while-drilling device suitable for use with one embodiment according to the present disclosure;

FIG. 2a illustrates the arrangement of source and sensors for one embodiment according to the present disclosure;

FIG. 2b shows an set of curves indicating signals generated by the arrangement of sensors for one embodiment according to the present disclosure;

FIG. 2c shows a set of curves aligned with the response of the sensors to the direct wave as time equals zero for one embodiment according to the present disclosure;

FIG. 3 shows a curve for one embodiment using a single seismic sensor according to the present disclosure; and

FIG. 4 shows a flow chart of a method according to one embodiment of the present disclosure.

DETAILED DESCRIPTION OF THE DISCLOSURE

[0012] The present disclosure relates to locating seismic features using one or more of seismic sensors located at a plurality of locations in a borehole. The location of seismic features while drilling may be beneficial for providing information for use in drilling operations, including, but not limited to, geosteering, geostopping, setting a casing point, adjusting properties of drilling fluids, and adjusting drilling parameters (weight-on-bit, rate of penetration, revolutions per minute, flow rate, etc.). Some non-limiting embodiments for locating seismic features follow below.

[0013] FIG. 1 shows a schematic diagram of a drilling system **10** with a drillstring **20** carrying a drilling assembly **90** (also referred to as the bottomhole assembly, or "BHA") conveyed in a "wellbore" or "borehole" **26** for drilling the borehole. The drilling system **10** includes a conventional derrick **11** erected on a floor **12** which supports a rotary table **14** that is rotated by a prime mover such as an electric motor (not shown) at a desired rotational speed. The drillstring **20** includes tubing such as a drill pipe **22** or a coiled-tubing extending downward from the surface into the borehole **26**. The drillstring **20** is pushed into the borehole **26** when a drill pipe **22** is used as the tubing. For coiled-tubing applications, a tubing injector, such as an injector (not shown), however, is used to move the tubing from a source thereof, such as a reel (not shown), to the borehole **26**. The drill bit **50** attached to the end of the drillstring breaks up the geological formations when it is rotated to drill the borehole **26**. If a drill pipe **22** is used, the drillstring **20** is coupled to a drawworks **30** via a kelly joint **21**, swivel **28**, and line **29** through a pulley **23.** During drilling operations, the drawworks **30** is operated to control the weight on bit, which is an important parameter that affects the rate of penetration. The operation of the drawworks is well known in the art and is thus not described in detail herein.

[0014] During drilling operations, a suitable drilling fluid **31** from a mud pit (source) **32** is circulated under pressure through a channel in the drillstring **20** by a mud pump **34.** The drilling fluid passes from the mud pump **34** into the drillstring **20** via a desurger (not shown), fluid line **38** and kelly joint **21.** The drilling fluid **31** is discharged at the borehole bottom **51** through an opening in the drill bit **50.** The drilling fluid **31** circulates uphole through the annular space **27** between the drillstring **20** and the borehole **26** and returns to the mud pit **32** via a return line **35**. The drilling fluid acts to lubricate the drill bit **50** and to carry borehole cutting or chips away from the drill bit **50**. A sensor $\mathbf{S_1}$ placed in the line **38** can provide information about the fluid flow rate. A surface torque sensor $\mathbf{S_2}$ and a sensor $\mathbf{S_3}$ associated with the drillstring **20** respectively provide information about the torque and rotational speed of the drillstring. Additionally, a sensor (not shown) associated with line **29** is used to provide the hook load of the drillstring **20**.

[0015] In one embodiment of the disclosure, the drill bit **50** is rotated by only rotating the drill pipe **22**. In another embodiment of the disclosure, a downhole motor **55** (mud motor) is disposed in the drilling assembly **90** to rotate the drill bit **50** and the drill pipe **22** is rotated usually to supplement the rotational power, if required, and to effect changes in the drilling direction.

[0016] In one embodiment of **Fig. 1**, the mud motor **55** is coupled to the drill bit **50** via a drive shaft (not shown) disposed in a bearing assembly **57.** The mud motor rotates the drill bit **50** when the drilling fluid **31** passes through the mud motor **55** under pressure. The bearing assembly **57** supports the radial and axial forces of the drill bit. A stabilizer **58** coupled to the bearing assembly **57** acts as a centralizer for the lowermost portion of the mud motor assembly.

[0017] In one embodiment of the disclosure, a drilling sensor module **59** is placed near the drill bit **50**. The drilling sensor module may contain sensors, circuitry, and processing software and algorithms relating to the dynamic drilling parameters. Such parameters can include bit bounce, stick-slip of the drilling assembly, backward rotation, torque, shocks, borehole and annulus pressure, acceleration measurements, and other measurements of the drill bit condition. A suitable telemetry or communication sub **77** using, for example, two-way telemetry, is also provided as illustrated in the drilling assembly **90**. The drilling sensor module processes the sensor information and transmits it to the surface control unit **40** via the telemetry system **77**.

[0018] The communication sub **77**, a power unit **78** and an MWD tool **79** are all connected in tandem with the drillstring **20**. Flex subs, for example, are used in connecting the MWD tool **79** in the drilling assembly **90**. Such subs and tools may form the bottom hole drilling assembly **90** between the drillstring **20** and the drill bit **50**. The drilling assembly **90** may make various measurements including the pulsed nuclear magnetic resonance measurements while the borehole **26** is being drilled. The communication sub **77** obtains the signals and measurements and transfers the signals, using two-way telemetry, for example, to be processed on the surface. Alternatively, the signals can be processed using a downhole processor at a suitable location (not shown) in the drilling assembly **90**.

[0019] The surface control unit or processor **40** may also receive one or more signals from other downhole sensors and devices and signals from sensors S_1-S_3 and other sensors used in the system **10** and processes such signals according to programmed instructions provided to the surface control unit **40**. The surface control unit **40** may display desired drilling parameters and other information on a display/monitor **44** utilized by an operator to control the drilling operations. The surface control unit **40** can include a computer or a microprocessor-based processing system, memory for storing programs or models and data, a recorder for recording data, and other peripherals. The control unit **40** can be adapted to activate alarms **42** when certain unsafe or undesirable operating conditions occur.

[0020] FIG. 2a shows a schematic of one embodiment according to the present disclosure. The drilling assembly **90** may include a plurality of seismic sensors **210**, **220**, **230**, positioned behind the location of the drill bit **50**. A seismic source **240** may be located at the surface and configured to generate seismic waves **250** in earth formation **260**. The direct seismic waves **250** may be reflected by a seismic feature such as seismic reflector **270**, thus forming reflected seismic waves **280**. The seismic reflector **270** may be any barrier that reflects seismic waves. Any boundary that has an acoustic impedance change across the boundary will reflect seismic waves. These include, but are not limited to, one or more of: (i) a limit between geological layers, (ii) a stratigraphical discordance, (iii) a fault, (iv) an interface between two fluids in rock. The use of three seismic sensors **210**, **220**, **230** is illustrative and exemplary only, as any number of seismic sensors may be used for embodiments of the present disclosure.

[0021] Seismic source **240** may be any seismic wave generating device, including, but not limited to, one or more of: (i) an airgun and (ii) a seismic vibrator. While seismic source **240** is shown at the surface in **FIG. 2a**, this location is exemplary and illustrative only, seismic source **240** may also be positioned in one of: (i) the same borehole as the seismic sensors, (ii) the drilling assembly, (iii) a nearby borehole. Seismic sensors **210**, **220**, **230** be any device configured to measure seismic waves, including, but not limited to, one or more of: (i) a hydrophone, (ii) a geophone, (iii) an accelerometer, and (iv) a microelectromechancial system (MEMS). The term "geophone" is intended to include a multicomponent geophone. Seismic sensors **210**, **220**, **230** may also include, or be in communication with, a clock, a memory unit, a processor, and a power source. In some embodiments, a seismic sensor **210**, **220**, **230** may include multiple sensing devices of the same or different types.

[0022] FIG. 2b. shows a set of curves **211**, **221**, **231** representing signals generated by seismic sensors **210**, **220**, **230** in response to waves **250**, **280**. Each set of curves **211**, **221**, **231** are shown as generated by signals at different positions along a drilling depth axis **205**. Herein, drilling depth refers to a distance of travel along the borehole **26**. A first set of pulses **213**, **223**, **233** represent the direct wave **250** detected at the respective seismic sensors **210**, **220**, **230**. Those versed in the art and having benefit of the present disclosure would recognize that normally, the direct arrival times may increase monotonically with the depth of the sensor. However, the direct arrival times may also be subject to large time drifts. In this particular example, the arrival time **233** does not monotonically increase with the depth of the sensor, which may be due to one or more of: (i) time drift and (ii) use of a different source excitation (and initiation time) than that corresponding to **213** and **223**. A second set of pulses **218**, **228**, **238** represent the reflected wave **280** detected at the respective seismic sensors **210**, **220**, **230**. The first set of pulses **213**, **223**, **233** and the second set of pulses **218**, **228**, **238** may be generated by the seismic sensors **210**, **220**, **230** independent of information regarding an initiation of the direct wave **250** by seismic source **240**. The first set of pulses **213**, **223**, **233** and the second set of pulses **218**, **228**, **238** define respective time gaps **215**, **225**, **235**.

[0023] FIG. 2c shows the set of curves **211**, **221**, **231** from **FIG. 2b** where the first set of pulses **213**, **223**, **233** are aligned such that the each encounter of the direct waves **250** with a seismic sensor **210**, **220**, **230** represents a beginning time, t=0. Then the second set of pulses **218**, **228**, **238** may be aligned by curve **290**. Curve **290** may be extrapolated to estimate the location of seismic reflector **270**. Curve **290** may be formed using a mathematical process, including, but not limited to, a regression technique.

[0024] FIG. 3 shows a graph of data points from a single seismic sensor **210** using another embodiment according to the present disclosure. The graph includes past data points **310** and a present data point **320** recorded by a seismic sensor **210** at different times. Each data point represents a time gap measured at a known drilling depth of the seismic sensor **210**. A curve **330** may be generated based on the past data points **310** and the present data point **320** using a curve fitting technique. The curve fitting technique may include, but is not limited to, one or more of: linear regression and polynomic regression. For example, those versed in the art and having benefit of the present disclosure would recognize that the reflection time of a planar reflector inclined to the borehole may be a quadratic or higher polynomic function. The curve **330** may be extrapolated to intersect an estimated point of intersection **340**, which represents the drilling depth where the time gap is estimated to decrease to zero and may be indicative of the location of the seismic reflector **270**. In some embodiments, additional information may be used to generate the curve **330**, including, but not limited to, velocity in the geological layer, and an inclination of the seismic reflector. The use of single seismic sensor at a plurality of unique drilling depths in exemplary and illustrative only, as a plurality of seismic sensors may be used where each seismic sensor generates signals at different drilling depths. In some embodiments, a plurality of curves, one for each seismic sensor, may be generated. The plurality of curves may be used to improve accuracy of the estimated point of intersection by one or more of: (i) comparing two or more of the plurality of curves and (ii) combining two or more of the plurality of curves.

[0025] FIG. 4 shows a flow chart of a method **400** according to one embodiment of the present disclosure. In step **410**, at least one seismic sensor **210**, **220**, **230** may be conveyed in a borehole **26**. In step **420**, at least one seismic wave **250** may be generated using a seismic source **240**. In step **430**, a plurality of signals **211**, **221**, **231** may be generated based on the detection of a first set of pulses **213**, **223**, **233** in response to the detection of direct wave **250** by the at least one seismic sensor **210**, **220**, **230** and the detection of a second set of pulses **218**, **228**, **238** in response to the detection of reflected wave **280** by the at least one seismic sensor **210**, **220**, **230**. In step **440**, time values may be assigned to each of the arrival times of the direct wave **250** and reflected wave **280** for each signal **211**, **221**, **231**. The time values assigned may be independent of the initiation time of the direct wave **250** by seismic source **240**. In step **450**, the plurality of signals **211**, **221**, **231** may be stored to a memory using a processor for later retrieval. In step **460**, at least one curve **290** may be generated by curve fitting the time gaps **215**, **225**, **235** between the first set of pulses **213**, **223**, **233** and the second set of pulses **218**, **228**, **238** and the unique drilling depths of the at least one seismic sensor **210**, **220**, **230** when the plurality of signals **211**, **221**, **231** were received. In step **470**, the location of a seismic reflector **270** may be estimated by extrapolating curve **290** to the point where the time gap is estimated to equal zero.

[0026] In some embodiments, the plurality of seismic sensors **210**, **220**, **230** may be conveyed to a new location in the borehole **26** after step **450** and then steps **420-450** may be repeated. In some embodiments, a plurality of curves may be generated using a plurality of seismic sensors where each of the plurality of seismic sensors generates a plurality of signals at a plurality of unique drilling depths. In some embodiments, the estimation of the location of seismic reflector **270** may include, but is not limited to, one or more of: (i) comparing at least one of the plurality of curves with another of the plurality of curves and (ii) combining at least two of the plurality of curves. In some embodiments, portions of steps **430-450** corresponding to the detection of the second set of pulses **218**, **228**, **238** in response to the detection of reflected wave **280** may be performed at the surface using analogous equipment (not shown) to that used in the borehole **26**.

[0027] The location of the seismic reflector **270** maybe estimated relative to one or more of: (i) a drilling direction, (ii) a direction normal to the seismic reflector **270**, and (iii) a direction normal to the drillstring **20**. In some embodiments, the orientation of the seismic reflector **270** may be estimated. In some embodiments, the curvature of the seismic reflector **270** may be estimated. In still other embodiments, the continuity of the seismic reflector **270** may be estimated.

[0028] The signals from the seismic sensors **210**, **220**, **230** may be stored in a memory by a processor. In some embodiments, the times of the direct and reflected waves may have time stamps assigned. The time stamps may be provided using a downhole clock (not shown) in or associated with drilling assembly **90**. The downhole clock accuracy may include a time drift of less than one millisecond per 100 seconds. The downhole clock may be synchronized prior to or while the drilling assembly **90** is in the borehole **26**. While in the borehole **26**, downhole clock may be synchronized by another clock in the borehole **26** or a surface clock. The surface clock may include one or more of: (i) a GPS clock, (ii) a quartz clock, and (iii) an atomic clock.

[0029] In some embodiments, the downhole clock may not require synchronization with another clock. Additionally, the method may be performed with a quartz clock or other clock having more time drift (around 1 milliseconds per 100 seconds), and consequently less expense, than higher accuracy clocks, such as microprocessor controlled ovenized oscillators and atomic clocks, which may also have larger power requirements.

[0030] The processor may be configured to start storing signals in the memory on detection of a reference event, where the reference event may include one or more of: (i) a first arrival wave, (ii) a direct wave, and (iii) a downgoing wave. The starting point of the reference event signal may include, but is not limited to, one of: (i) a first break, (ii) a first peak, (iii) a first trough, and (iv) a point of largest amplitude.

[0031] The processor may also be configured to process the signals received by the seismic sensors **210**, **220**, **230**, where processing may include, but is not limited to, one or more of: (i) resampling, (ii) filtering, (iii) stacking, (iv) averaging, (v) correlation, (vi) cross-correlation, (vii) amplitude normalization, (viii) event picking, and (ix) statistical estimation. In some embodiments, processing may be performed in real time or at the surface.

[0032] Signals maybe be transmitted to the surface, either pre- or post-processing, using, but not limited to, one or more of: (i) mud-pulse telemetry, (ii) wired-pipe telemetry, (iii) electromagnetic telemetry, (iv) acoustic telemetry, and (v) a memory download at the surface.

[0033] The apparatus for use with the present disclosure may include a downhole processor that may be positioned at any suitable location within or near the bottom hole assembly. The use of the processor is described below.

[0034] The processing of the data may be done by a downhole processor and/or a surface processor to give corrected measurements substantially in real time. Implicit in the control and processing of the data is the use of a computer program on a suitable machine readable medium that enables the processor to perform the control and processing. The machine readable medium may include ROMs, EPROMs, EEPROMs, Flash Memories, and Optical disks. Such media may also be used to store results of the processing.

[0035] While the foregoing disclosure is directed to specific embodiments of the disclosure, various modifications will be apparent to those skilled in the art. It is intended that all such variations within the scope and spirit of the appended claims be embraced by the foregoing disclosure.

CLAIMS

We claim:

1. A method of performing measurements while drilling in an earth formation, the method comprising:

   estimating a location of a seismic reflector using (i) a plurality of signals from at least one seismic sensor, each signal being generated at a unique drilling depth and indicative of a direct wave and a reflected wave, and (ii) the at least one unique drilling depth for the at least one seismic sensor;

   wherein a time of initiation of the direct wave is indeterminate to a clock associated with the at least one seismic sensor.

2. The method of claim 1, wherein the seismic reflector includes a boundary between two layers with differing lithologies.

3. The method of claim 1, further comprising:

   assigning time values for the arrival times of the direct wave and the reflected wave at the at least one seismic sensor at the at least one drilling depth.

4. The method of claim 3, further comprising:

   storing the time values to a memory.

5. The method of claim 1, further comprising:

   generating the direct wave using at least one seismic source.

6. The method of claim 1, further comprising:

   transmitting the plurality of signals to the earth's surface;

7. The method of claim 1, further comprising:

   conveying the at least one seismic sensor in a borehole in the earth formation.

8. The method of claim 1, wherein estimating the location of the seismic reflector includes determining a time gap between the arrival times of the direct wave and the reflected wave for the at least one seismic sensor.

9. The method of claim 1, wherein estimating the location of the seismic reflector includes using a regression calculation.

10. The method of claim 1, wherein the at least one seismic sensor comprises a plurality of seismic sensors, and wherein the plurality of signals comprises a plurality of signals from each of the plurality of seismic sensors.

11. The method of claim 10, wherein estimating the location of the seismic reflector comprises:

    generating a plurality of curves, wherein each curve is based on the plurality of signals from one of the plurality of seismic sensors; and

    estimating the location of the seismic reflector using at least two of the plurality of curves.

12. A non-transitory computer-readable medium product having instructions thereon that, when executed, cause at least one processor to perform a method, the method comprising:

    estimating a location of a seismic reflector using (i) a plurality of signals from at least one seismic sensor, each signal being generated at a unique drilling depth and indicative of a direct wave and a reflected wave, and (ii) the at least one unique drilling depth for the at least one seismic sensor;

    wherein a time of initiation of the direct wave is indeterminate to a clock associated with the at least one seismic sensor.

13. The non-transitory computer-readable medium product of claim 12 further comprising at least one of: (i) a ROM, (ii) an EPROM, (iii) an EEPROM, (iv) a flash memory, or (v) an optical disk.

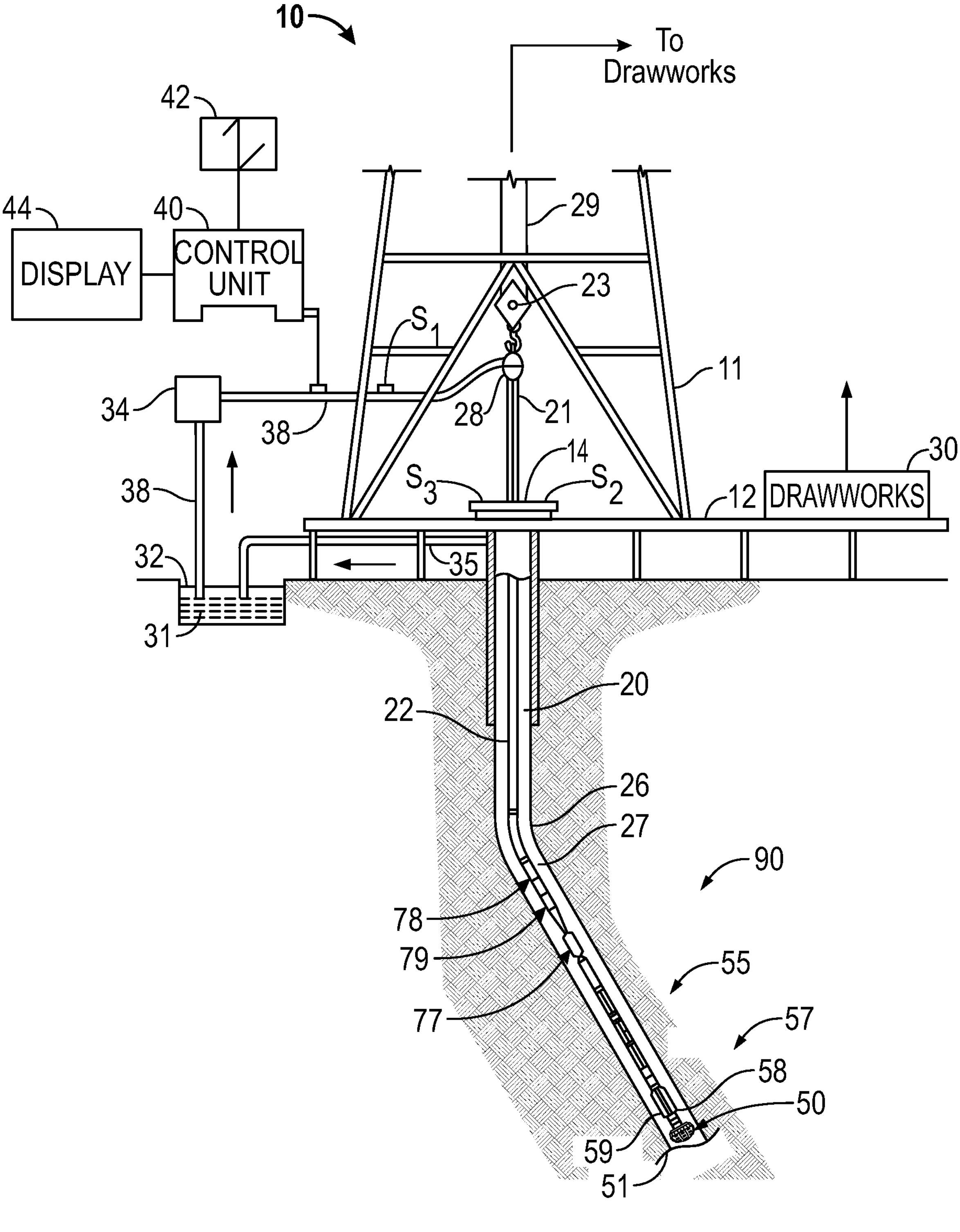
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FIG. 1

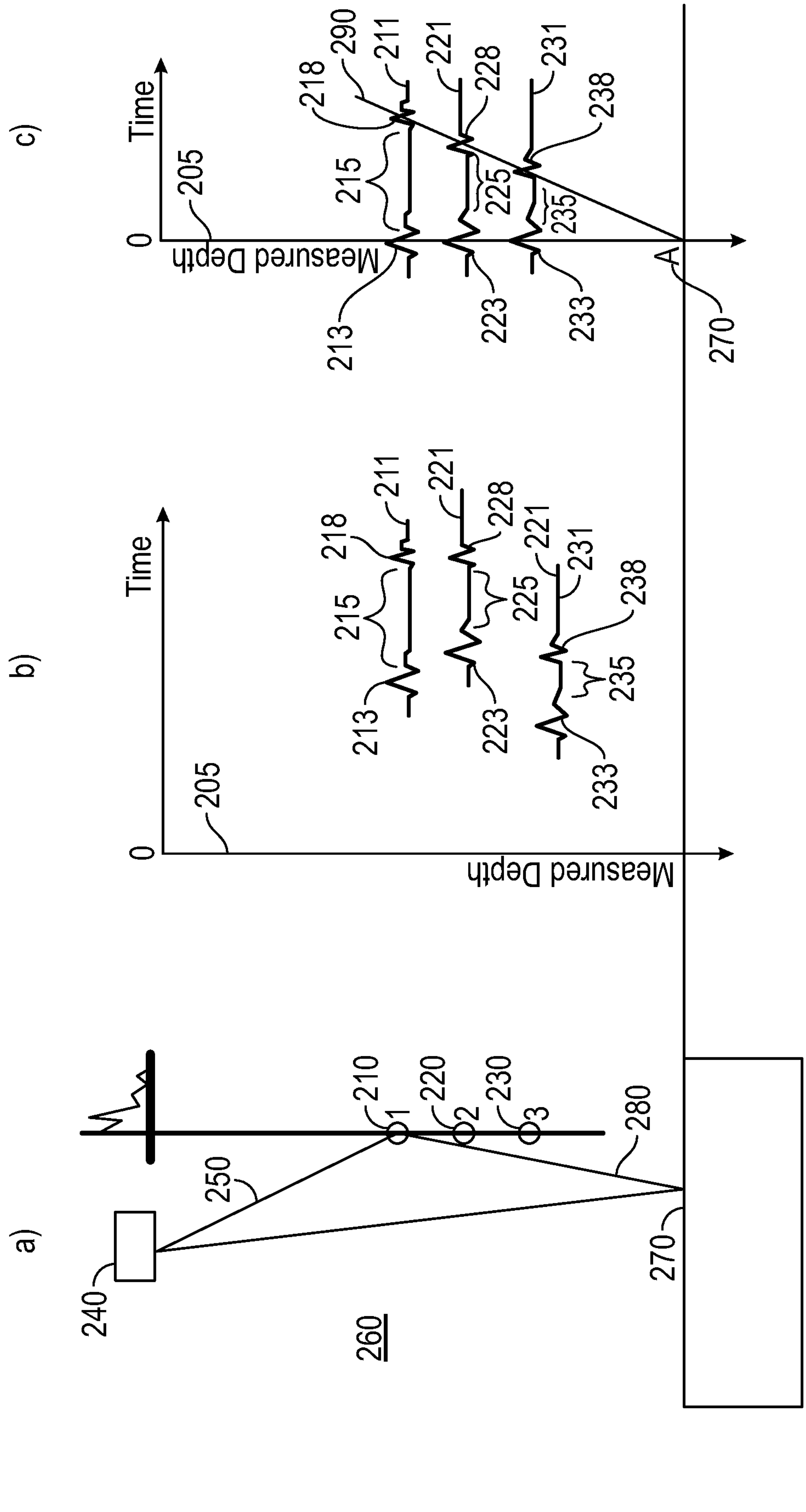
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FIG. 2

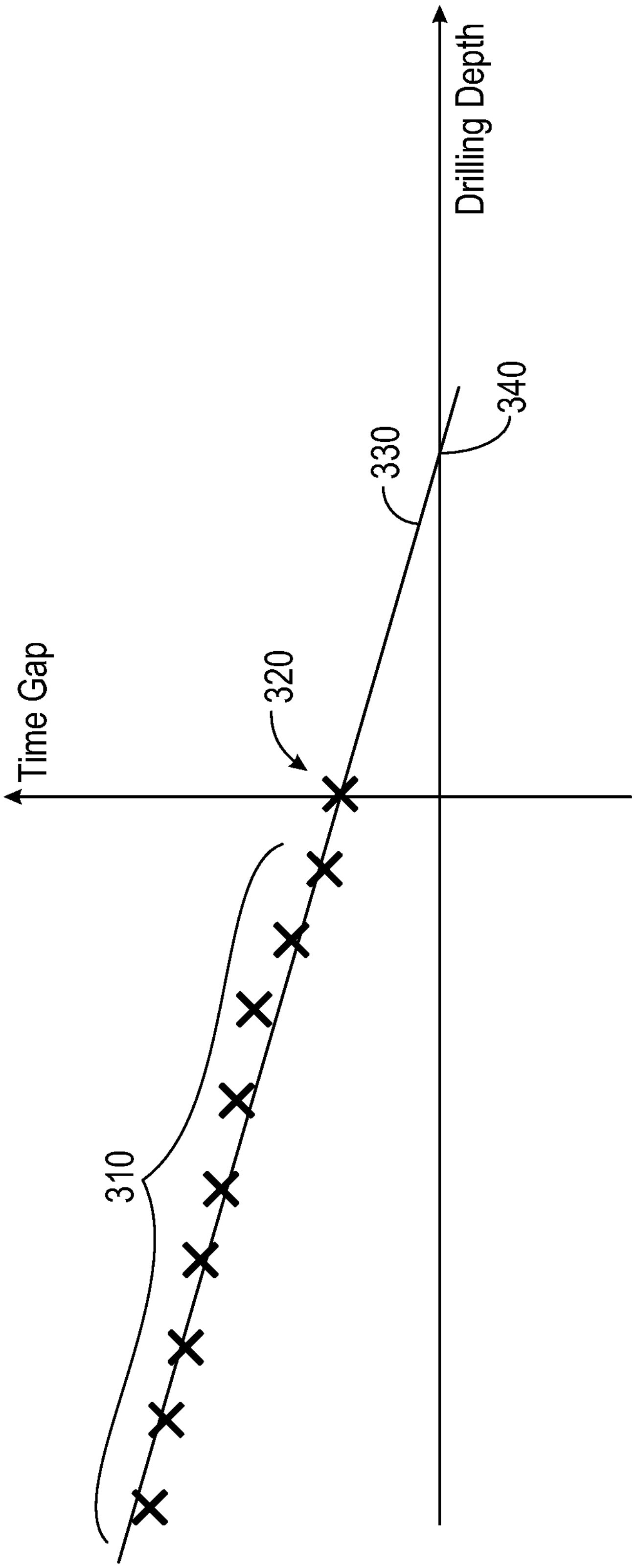

FIG. 3

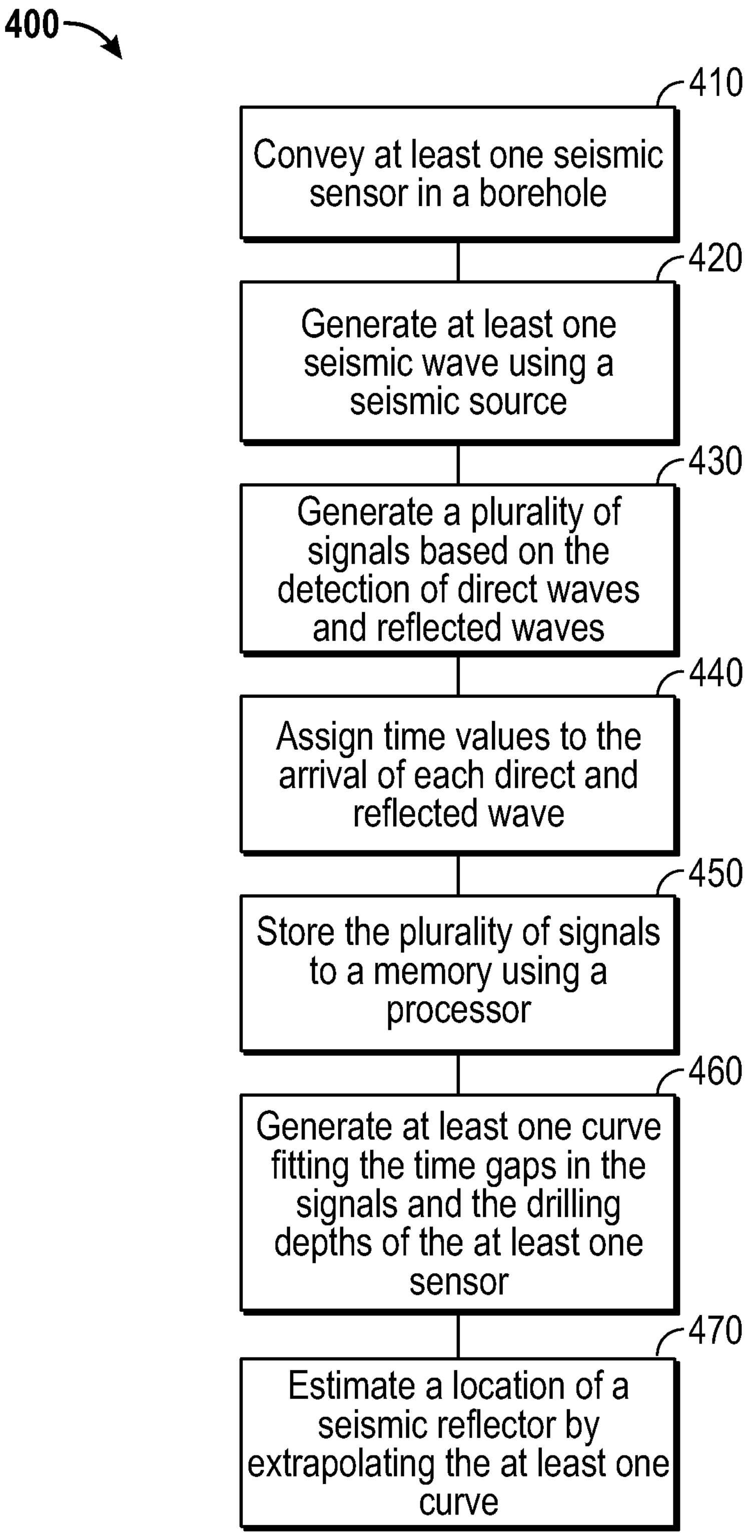
400
410
Convey at least one seismic sensor in a borehole
420
Generate at least one seismic wave using a seismic source
430
Generate a plurality of signals based on the detection of direct waves and reflected waves
440
Assign time values to the arrival of each direct and reflected wave
450
Store the plurality of signals to a memory using a processor
460
Generate at least one curve fitting the time gaps in the signals and the drilling depths of the at least one sensor
470
Estimate a location of a seismic reflector by extrapolating the at least one curve

FIG. 4