



(51) International Patent Classification:

E21B 44/00 (2006.01) *E21B 47/135* (2012.01)
E21B 43/24 (2006.01) *E21B 7/00* (2006.01)
E21B 43/30 (2006.01) *E21B 7/04* (2006.01)
E21B 47/09 (2012.01)

(21) International Application Number:

PCT/CA2013/050374

(22) International Filing Date:

15 May 2013 (15.05.2013)

(25) Filing Language:

English

(26) Publication Language:

English

(71) Applicant: **EVOLUTION ENGINEERING INC.**
 [CA/CA]; #2, 1460 28 Street NE, Calgary, Alberta T2A
 7W6 (CA).

(72) Inventors: **LOGAN, Aaron W.**; 48 Slocan Road SW, Cal-
 gary, Alberta T2W 0S8 (CA). **LOGAN, Justin C.**; #301,
 1441 23rd Avenue SW, Calgary, Alberta T2T 0T6 (CA).

(74) Agents: **MANNING, Gavin N.** et al.; c/o Oyen Wiggs
 Green & Mutala LLP, 480 - The Station 601 West Cordova
 Street, Vancouver, British Columbia V6B 1G1 (CA).

(81) Designated States (*unless otherwise indicated, for every
 kind of national protection available*): AE, AG, AL, AM,
 AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY,
 BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM,
 DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT,
 HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP,
 KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD,
 ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI,
 NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU,
 RW, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ,
 TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA,
 ZM, ZW.

(84) Designated States (*unless otherwise indicated, for every
 kind of regional protection available*): ARIPO (BW, GH,
 GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, SZ, TZ,
 UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ,
 TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK,
 EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV,

[Continued on next page]

(54) Title: METHOD AND APPARATUS FOR DOWNHOLE WELLBORE PLACEMENT

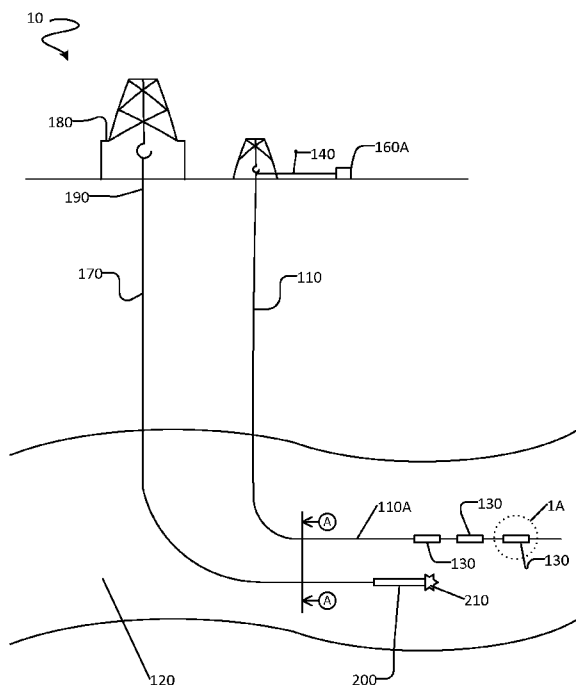


FIG. 1

(57) Abstract: A method of drilling multiple wellbores in close proximity to one another involves providing a primary wellbore; equipped with a fiber Bragg grating sensor (FBG) line. The FBG sensor line extends along at least a portion of the primary wellbore. The method drills at least one secondary wellbore using a directional drill. Data from the FBG sensor line is processed to determine locations of acoustic sources corresponding to the directional drill relative to the FBG sensor line. Locations of the acoustic sources are used to compare a trajectory of the secondary wellbore to a desired trajectory. Corrections to the trajectory may be made as the secondary wellbore is drilled. The methods may be applied, for example, to drilling formations of wellbores for SAGD applications. Associated apparatus and computer program products are also described.

WO 2014/183187 A1



MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, **Published:**

SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, — *with international search report (Art. 21(3))*
GW, ML, MR, NE, SN, TD, TG).

METHOD AND APPARATUS FOR DOWNHOLE WELLBORE PLACEMENT

Technical Field

[0001] This invention relates to subsurface drilling, specifically to apparatus and method for downhole wellbore placement. Embodiments are applicable, for example, to drilling
5 wells for recovering hydrocarbons.

Background

[0002] Recovering hydrocarbons from subterranean zones primarily involves drilling wellbores.

[0003] Wellbores are made using surface-located drilling equipment which drives a drill
10 string that eventually extends from the surface equipment to the formation or subterranean zone of interest. The drill string can extend thousands of feet or meters below the surface. The terminal end of the drill string includes a drill bit for drilling (or extending) the wellbore. Drilling fluid usually in the form of a drilling “mud” is typically pumped through the drill string. The drilling fluid cools and lubricates the drill bit and also carries
15 cuttings back to the surface. Drilling fluid may also be used to help control bottom hole pressure to inhibit hydrocarbon influx from the formation into the wellbore and potential blow out at surface.

[0004] Bottom hole assembly (BHA) is the name given to the equipment at the terminal end of a drill string. In addition to a drill bit a BHA may comprise elements such as:
20 apparatus for steering the direction of the drilling (e.g. a steerable downhole mud motor or rotary steerable system); sensors for measuring properties of the surrounding geological formations (e.g. sensors for use in well logging); sensors for measuring downhole conditions as drilling progresses; systems for telemetry of data to the surface; stabilizers; heavy weight drill collars, pulsers and the like. The BHA is typically advanced into the
25 wellbore by a string of metallic tubulars (drill pipe).

- [0005] Telemetry information can be invaluable for efficient drilling operations. For example, telemetry information from a downhole probe may be used by a drill rig crew to make decisions about controlling and steering the drill bit to optimize the drilling speed and trajectory based on numerous factors, including legal boundaries, locations of existing wells, formation properties, hydrocarbon size and location, etc. A crew may make intentional deviations from the planned path as necessary based on information gathered from downhole sensors and transmitted to the surface by telemetry during the drilling process. The ability to obtain real time data allows for relatively more economical and more efficient drilling operations.
- 5
- [0006] In many cases it is not only critical to be able to track the drilling of boreholes at subsurface locations, but also to be able to determine the relative location of one borehole, such as a reference well, to another borehole being drilled.
- 10
- [0007] For example, in SAGD production of heavy oil, the placement of two coplanar wells, one (upper) injector and one (lower) producer is important. Ideally, the two wells will pass through a formation coplanar to one another such that a distance between the wellbores is consistent. MWD data is typically not accurate enough to maintain a desired separation between different SAGD wellbores. The cumulative error associated with taking a geometric measurement (such as the wellbore depth, azimuthal headings and inclination) at certain points during the drilling process and having those measurements reference the relative previous measurement leads to progressively larger and larger error window with respect to the absolute placement of the active wellbore.
- 15
- 20
- [0008] Magnetic ranging may be used to determine the relative position of one well with respect to another, or to some surface reference, using magnetic measurements. Various magnetic ranging technologies are available in the marketplace. Active ranging utilizes a precisely positioned electromagnetic source or a rotating rare-earth magnet fixed to the BHA. In areas where magnetic interference may be prevalent, systems have used Gravity MWD (GMWD) providing azimuth with two sets of directional survey accelerometers to determining BHA bend and wellbore positioning. In passive magnetic ranging or magnetostatic methods, the current state of magnetism of a casing of the reference well is measured.
- 25
- 30

[0009] Magnetic ranging has been used for a variety of applications such as but not limited to, positioning of blow out wells, planned (or avoidance) of intersection of one well with another, wellbore placements for Steam Assisted Gravity Drainage or SAGD, and construction of wellbores for nuclear wastes.

5 [0010] Other wellbore placement systems include a sonic telemetry system utilizing time of flight (TOF) ranging as described in CA 2692907. US2010/0200296 describes another wellbore placement system, where a series of acoustic generators are deployed in a drill string and their emitted signal is picked up by geophones on the earth's surface; the subsurface positions of these acoustic generators are then computed by a complex
10 geophone position and time of flight data analysis.

[0011] In addition to the use of optical fiber sensor arrays for measurement of pressure and temperature in production monitoring wells, optical fiber has also assisted in measurement of seismic changes. WO 2012/123760 describes a method involving optical fiber deployed along substantially the entire length of the wellbore to provide distributed
15 acoustic sensing and detecting the acoustic response to seismic stimulus. The data can provide information related to time of arrival of incident seismic waves at various sensing portions of fiber and also reflections of seismic waves to ascertain a seismic profile.

[0012] The use of fiber optic distributed acoustic sensors (DAS) in wellbores has been proposed for monitoring various steps in well formation and operation. WO2010/136768
20 describes the use of measurement of acoustic signals and monitoring sections of fiber in the vicinity of the drill as it advances through a well to provide real time feedback to the driller. Also, WO2012/094086 describes use of fiber optic sensors for monitoring vibration in the downhole environment.

[0013] Fiber optic sensors have been applied in MWD applications as described in CA
25 2664523 utilizing optical fiber to measure parameters of interest and to communicate data.

[0014] The following references describe various systems for ranging, wellbore placement and telemetry: WO 2007/145859; WO2009/056855; WO 2012/094086; WO 2012/123760; WO 2012/072973; CA 2147610; CA 2187487; CA 2202460;

CA 2279539; CA 2250769; CA 2476787; CA 2721342; CA 2581716; CA 2588135;
CA 2692907; CA 2721443; CA 2760644; CA 2664523; CA 2691462; CA 2753234;
US 2010/0200296.

- 5 [0015] Despite work that has been done to develop systems for ranging, wellbore placement and ability to monitor in real time various parameters of interest, there remains a need for practical and cost effective systems capable of guiding placement of wellbores with high accuracy. Such systems would be advantageous, for example, for drilling sets of boreholes according to complex well geometries.

Summary

- 10 [0016] The invention has several aspects. One aspect provides methods for downhole wellbore placement during drilling. Another aspect provides apparatus for downhole wellbore placement during drilling. Another aspect provides computer readable media storing computer executable instructions for implementing methods for drilling.

Brief Description of the Drawings

- 15 [0017] The accompanying drawings illustrate non-limiting example embodiments of the invention.

[0018] Figure 1 is a schematic view of a drilling operation showing placement of two wellbores in close proximity according to an example embodiment.

[0019] Figure 1A shows a schematic exploded view of section 1A in Figure 1.

- 20 [0020] Figure 1B schematically shows the optical processing equipment in Figure 1.

[0021] Figure 1C is a graphical representation showing the reflectivity profile of example fiber Bragg grating sensors.

[0022] Figure 2 is a schematic view showing steam envelope potential problems and/or errors that may occur when drilling a SAGD pair.

[0023] Figure 3 is a cross sectional view in the plane A-A of a portion of the wellbores shown in Figure 1 showing co-planar alignment and wellbore placement requirements.

[0024] Figure 4 shows schematically a noise generating device producing an acoustic signature received by a secondary wellbore downhole fiber Bragg grating.

5 [0025] Figures 5A to 5D show schematically a number of different example noise sources.

[0026] Figure 6 is a schematic view according to another example embodiment showing a noise generating device producing an acoustic signature received by a fiber Bragg grating on the surface.

[0027] Figure 7 is a 3D isometric view of multiple SAGD fiber Bragg grating wellbores.

10 Description

[0028] Throughout the following description specific details are set forth in order to provide a more thorough understanding to persons skilled in the art. However, well known elements may not have been shown or described in detail to avoid unnecessarily obscuring the disclosure. The following description of examples of the technology is not
15 intended to be exhaustive or to limit the system to the precise forms of any example embodiment. Accordingly, the description and drawings are to be regarded in an illustrative, rather than a restrictive, sense.

[0029] Figure 1 shows schematically an example drilling operation 100, in which it is desired to drill a plurality of boreholes having a specified geometric relationship to one
20 another. For example, it may be desired to drill an array of boreholes that are all parallel to one another. The illustrated embodiment shows Steam Assisted Gravity Drainage (SAGD) drilling but this is just exemplary. the invention is not limited to drilling wells for SAGD.

[0030] A primary wellbore 110 with a horizontal section 110A is drilled through a
25 formation of interest 120. Drilling can be done, for example, by means of directional drilling techniques known to those skilled in the art. Horizontal section 110A may be

equipped with a ranging device 130. Ranging device 130 may be in the form of optical fiber 140. Optical fiber 140 may extend substantially through the entire length of wellbore 110 and horizontal section 110A. In some embodiments, optical fiber 140 may extend through the entirety of wellbore 110 and horizontal section 110A. Installation of ranging
5 device 130 within wellbore 110 and horizontal section 110A may be conducted using methods known to those skilled in the art.

[0031] Optical fiber 140 has a core 140A and cladding 140B. Optical fiber 140 may also include additional coatings or protective layers as desired. One or more fiber Bragg gratings 150, are formed within optical fiber 140 using methods known to those skilled in
10 the art. In some embodiments, fiber Bragg gratings 150 are spaced apart from one another by distances in the range of a few meters to 100 meters or more. In a preferred example embodiment, SAGD boreholes containing fiber Bragg gratings are spaced apart from one another by a distance in the range of 5 to 20 meters.

[0032] Optical fiber 140 connects fiber Bragg gratings 150 to optical signal processing
15 equipment 160A. Fiber Bragg grating sensors, as known, provide a periodic refractive index variation in the core of an optical fiber that causes reflection of a narrow wavelength band of light. A fiber Bragg grating 150 has a maximum reflectivity at a central reflectivity wavelength and transmits other wavelengths. Each fiber Bragg grating 150 reflects a narrow wavelength band of light having a central wavelength. Each fiber Bragg
20 grating 150 may be constructed to reflect light in a different wavelength band and central wavelength such that the signals from different fiber Bragg gratings 150 may be detected using Wavelength Division Multiplexing (WDM) techniques.

[0033] Referring to Figure 1A, in an exemplary embodiment, optical signal processing
equipment 160A includes a broadband source of light 161 and appropriate equipment for
25 coupling the light into optical fiber 140, (e.g. a coupler 162). Additionally, optical signal processing equipment 160A includes appropriate signal analysis equipment 163 for detecting and analyzing the return signals from fiber Bragg gratings 150.

[0034] In operation, broadband light 300 passes through optical fiber 140 until it reaches the first fiber Bragg grating 150-1. First fiber Bragg grating 150-1 reflects a narrow

wavelength band of light having a central wavelength λ_1 . Light 301 not reflected by first fiber Bragg grating 150-1 is transmitted toward a second fiber Bragg grating 150-2 which reflects a narrow wavelength band of light having a central wavelength λ_2 . Light 302 not reflected by the second fiber Bragg grating 150-2 is transmitted to the next fiber Bragg
5 grating. The process continues until light has passed by N fiber Bragg gratings resulting in N different reflected light signals each having a different wavelength. The end of fiber optic 140 may be terminated in an anti-reflective manner.

[0035] Fiber Bragg gratings are well suited for use as sensor elements. A measurand, such as a dynamic strain induced by acoustic waves will induce a change in the fiber
10 Bragg grating spacing and/or reflectivity characteristics, which changes the wavelength of the light reflected by the fiber Bragg grating. The wavelength reflected by the fiber grating is directly related to the value (magnitude) of the measurand. Therefore, optical fiber 140 may be used to measure features such as acoustic fields at the locations of fiber Bragg gratings 150 by monitoring the wavelengths of light reflected by the different fiber
15 Bragg gratings 150.

[0036] Given the discrete or segmented configuration integral to the function of the fiber Bragg grating, a system comprising a fiber optic sensor incorporating one or more fiber Bragg gratings may be used to detect acoustic fields at a precise location (or preferably multiple locations) within the wellbore. According to some embodiments, fiber Bragg
20 gratings deployed in one or more wellbores are used to localize sources of acoustic signals associated with the creation of other wellbores. This information may be used to steer drilling on the other wellbores to achieve a desired arrangement of two or more wellbores. Acoustic signals detected using fiber Bragg gratings may be used in combination with inputs from other sensors for more accurate placement measurement.

25 [0037] Figure 1 shows an example secondary wellbore 170 being drilled using a drill rig 180 which drives a drill string 190. Any suitable directional drilling methods may be applied to guide the drilling of secondary wellbore 170 (including directional drilling methods known to those skilled in the art). A bottom hole Assembly (BHA) 200 is attached to the bottom of drill string 190 and has a drill bit 210 attached to a bottom end

thereof. BHA 200 may comprise multiple sections of drill string 190 and may incorporate a measurement while drilling (MWD) system.

[0038] In principle, fiber Bragg gratings 150 positioned within primary wellbore 110 will experience dynamic strain from the acoustic signals originating from BHA 200 within secondary wellbore 170. Acoustic signals may, for example, be generated by the interaction of drill bit 210 with the formation it is drilling into, drilling fluid pulsations (e.g. pulsations generated by a mud hammer or other pulser that is optionally incorporated in BHA 200), sound generated by the operation of a mud motor driving the drill bit or the like. Sound propagates from BHA 200 to fiber Bragg gratings 150. The interaction of the sound with the fiber Bragg gratings causes dynamic strain on the fiber Bragg gratings. This strain will cause wavelength shifts in the central wavelength of the narrow band of light reflected by fiber Bragg gratings 150. The wavelength shifts may be processed to determine the amplitude and other characteristics (e.g frequency spectrum) of the acoustic fields causing the dynamic strain.

[0039] For example, when the first fiber Bragg grating 150-1 is subjected to dynamic strain from the acoustic waves generated by the acoustic signature generating devices, the central wavelength $\lambda_1(t)$ is shifted by an amount $\Delta\lambda_1(t)$ to a new wavelength $\lambda_1'(t)$. The wavelengths reflected by different fiber Bragg gratings 150 are separated and designed to provide a wavelength spacing such that when the central wavelength of one fiber Bragg grating 150 is shifted by a maximum amount associated with a maximum dynamic strain, the resulting reflected wavelength will still be in a desired band ω which does not overlap with bands associated with any of the other fiber Bragg gratings 150. Therefore, as shown in Figure 1C, the shifted central wavelength $\lambda_1'(t)$ for fiber Bragg grating 150-1, will always be within band ω_1 , which does not overlap with any of bands $\omega_2 \dots \omega_N$ of fiber Bragg gratings 150-2 .. 150-N, respectively.

[0040] Referring to Figure 1B, the reflected optical signals $\lambda_1'(t) \dots \lambda_N'(t)$ (not shown) are provided via optical fiber 140 and coupler 162 to signal analysis equipment 163. In order to separate the signals from different fiber Bragg gratings 150, the return optical signals are directed to a wavelength-demultiplexer 400 (such as a selective filter, a set of selective filters, a spectrometer or the like). In one embodiment, wavelength-demultiplexer 400

provides separate outputs associated with different fiber Bragg gratings 150 to be analyzed using sensitive wavelength or phase discrimination equipment 402 which detects, demodulates and performs wavelength or phase discrimination to detect wavelength modulation due to acoustic signals detected at fiber Bragg gratings 150.

- 5 **[0041]** The output of wavelength or phase discrimination equipment 402 is provided to a processor/controller 404 for processing, storage in memory 405, display 406 to a user, or for any other desired use. Processor 404 may be provided with a user interface 407 for user input and control.

- 10 **[0042]** Ranging device 130 including fiber Bragg gratings 150 and/or signal analysis equipment 163 may be provided by a commercially-available fiber Bragg grating sensor system. Examples of such systems include fiber Bragg grating sensors available from HiFi Engineering, Inc. of Calgary, Alberta, Canada, fiber integrators available from Optiphase, Inc. of Van Nuys, California as well as high performance computing
15 gratings may be processed using such commercially-available fiber Bragg grating sensor systems to yield information regarding the relative positions and signal strengths of acoustic sources. Time of flight manipulations may then be conducted to determine the exact position of the sensors based on the signal strength and sensor relative position.

- 20 **[0043]** Processor 404 may be configured to localize acoustic sources based upon amplitude and/or other characteristics of acoustic signals detected at fiber Bragg gratings 150. In some embodiments, processor 404 may be configured to separately identify components of acoustic signals detected at fiber Bragg gratings 150 that arise from two or more distinct acoustic sources and to localize each of the sound sources based on the detected acoustic signals. Acoustic signals from different sources may be identified by
25 their different acoustic signatures. For example, in one embodiment, detected acoustic signals are subjected to a frequency spectrum analysis (e.g. processed using a discrete Fourier transform algorithm). Components of the detected acoustic signals originating from different acoustic sources may have different acoustic frequencies or sets of frequencies and may therefore be separated by processor 404 in the frequency domain.

[0044] For example, BHA 200 may comprise one or more acoustic signature generating devices located at known locations relative to drill bit 210. Processor 404 may be configured to separately detect acoustic signal components arising from drill bit 210 and one or more separate acoustic signal generating devices.

5 [0045] Figure 2 schematically shows a portion of an array of wellbores for use in SAGD and illustrates why it is desirable to control the positions of the wellbores. Where two wellbores come too close together a “steam short circuit” may result (where steam effectively breaches across the zone, represented by the dashed line, into the second wellbore, leaving the remaining “producing zone” un-energized by steam and thus not
10 producing). Figure 2 also shows that cold zones where the primary and secondary wells are outside the “production zone”, such that steam is not able to heat the zone of interest to encourage production and is thus ineffective. Problems of these types may be reduced by precision drilling of SAGD wellbore arrays.

[0046] Figure 3 is a schematic cross section view of the horizontal section 110A of
15 primary wellbore 110 and secondary wellbore 170 taken in the plane A-A in Figure 1. In Figure 3, secondary wellbore 170 is shown to be in close proximity and coplanar alignment to horizontal section 110A of primary wellbore 110.

[0047] Primary wellbore 110 may be drilled using any suitable directional drilling method. A first fiber Bragg ranging sensor array 130 is installed in primary wellbore 110.
20 After first fiber Bragg ranging sensor array 130 has been installed it can be applied to localize another wellbore being drilled nearby wellbore 110. For example, another primary wellbore 110-1 may be drilled, using directional drilling so that it is oriented to be in the same horizontal plane and a distance x away from primary wellbore 110. MWD measurements may be obtained from telemetry tools (not shown) in BHA 200 in order to
25 determine inclination, azimuth and depth of BHA 200 during drilling.

[0048] One or more acoustic signals originating from points in BHA 200 within wellbore 110-1 during drilling are received by fiber Bragg gratings 150. Optical signals $\lambda_1' \dots \lambda_N'$ from fiber Bragg gratings 150 are detected and processed by processor 404. Since the location of each of fiber Bragg gratings 150 is known and the intensity of acoustic signals

at these locations can be determined by processing optical signals $\lambda_1' \dots \lambda_N'$, the distance of acoustic sources in or associated with BHA 200 from fiber Bragg gratings 150 may be determined. Other ways to determine distances between one or more acoustic sources and fiber Bragg gratings 150 are time-of-flight measurements such as measuring the relative acoustic phase at different fiber Bragg gratings 150 or determining the relative times at which recognizable acoustic features are detected at different fiber Bragg gratings 150. These distances may be used to determine whether wellbore 110-1 is progressing toward or away from wellbore 110. These distances may be used in conjunction with information from MWD measurements to better pinpoint the location of drill bit 210 and BHA 200 relative to wellbore 110.

[0049] For example, if BHA 200 during drilling has just passed the first fiber Bragg grating 150-1, the intensity of the acoustic signal near fiber Bragg grating 150-1 would be stronger than the intensity of the acoustic signal at other fiber Bragg gratings 150. The difference in amplitude of the acoustic signal at different fiber Bragg gratings 150 will depend on how the acoustic signal is attenuated by the formation through which it passes. Time of flight acoustic measurements may additionally or in the alternative indicate the position(s) of acoustic emitters in BHA 200. Time-of-flight measurements may be affected by variations in the speed of sound in the formation in which the wellbore are being made. These variations are often not a concern. Especially where distances between boreholes are small the properties of the formation can be expected to be fairly uniform between the boreholes in most cases. In cases where anomalies exist due to sound travelling through formations in the earth having different acoustic transmission properties, the anomalies can be modeled and corresponding corrections or adjustments may be applied. Similar corrections are applied in the field of seismic prospecting. Techniques used in seismic prospecting to model and correct for the presence of formations having different acoustic transmission properties may be applied also in the context of the present invention. As additional fiber Bragg gratings are installed in subsequent wellbores, the anomalies are easier to correct and adjust for due to the increase in sample size of the data used to model the correction.

[0050] The combination of MWD telemetry measurements and acoustic intensity measurements may be used to maintain the two wellbores 110 and 110-1 coplanar (e.g. in

a horizontal plane) by applying corrections as to how BHA 200 is steered during drilling. The same process may be applied to drill additional primary wellbores in the same horizontal plane.

[0051] Ranging sensors 130 comprising optical fibers having fiber Bragg gratings may be installed within each wellbore. The additional fiber Bragg sensors can receive acoustic signals from the operation of drill bit 210 and/or other acoustic sources in BHA 200. Relative distances from the acoustic sources can be determined from the acoustic signals (for example, by determining the amplitude of the acoustic signals at different fiber Bragg gratings 150 and/or by time-of-flight acoustic measurements as described above and assuming an attenuation function for the acoustic signals. This information can be used to calculate the position of drill bit 210 and BHA 200 relative to the existing wellbores.

[0052] Once two wellbores are drilled as described above, a secondary wellbore 170 may be drilled, in the same manner as primary wellbore 110-1 using directional drilling. The secondary wellbore may, for example, be drilled to have a horizontal section located in a plane vertical to one of the primary wellbores, for example, wellbore 110. Secondary wellbore 170 is maintained during the drilling operation at a substantially fixed distance y from primary wellbore 110. Corrections to the steering of secondary wellbore 170 may be determined based on two independent measurements, namely: the relative position of the primary and secondary wellbores and the “normal” geometric measurement and location for secondary wellbore 170. The acoustic signal(s) generated by BHA 200 in secondary wellbore 170 will now be received by two independent fiber optic lines each having fiber Bragg sensors, which in turn provide reflected optical signals to processor 404. Therefore, processor 404 will have access to multiple reference points in space that are not all located along the same line. The relative distances of these reference points to acoustic sources associated with BHA 200 can be determined from the intensities of the acoustic signals. This information in turn allows for determining the location of acoustic sources in BHA 200 by triangulation in 3D space relative to primary wellbores 110 and 110-1.

[0053] The determined 3D coordinates of BHA 200 may be used to determine whether secondary wellbore 170 may require a course correction by moving it in the up, down, left or right direction, relative to primary wellbore 110, in order to keep secondary wellbore

170 in a desired spacing and alignment with primary wellbore 110. The necessary correction may be applied by steering drill bit 210 in any suitable manner.

[0054] Drilling other secondary wellbores (a secondary wellbore 170 may be drilled adjacent to each of the primary wellbores) may be done using the same process described above. As each additional wellbore is drilled and equipped with its own fiber Bragg grating sensors, the accuracy of 3D placement of other wellbores relative to the wellbores already drilled can be improved since the number of locations corresponding to fiber Bragg gratings 150 is increased and also covers a larger volume. This can provide multiple known reference points in space relative to the BHA during drilling, which will enable generating highly defined geometric placement and 3D location of live wellbores as seen in Figure 7.

[0055] Processor 404 may process received information characterizing the acoustic signals received at fiber Bragg gratings 150 to reverse triangulate a precise location of the noise source(s) from drilling another wellbore. This process may be performed continuously or periodically while wellbores are drilled. The result can be real time or near real time tracking of the path of the wellbore. This path can be compared to a desired path to determine whether corrections are necessary.

[0056] Corrections to the path of a wellbore being drilled (e.g. a wellbore 170) may be presented in the form of information or instructions to a user on a display or may be communicated to the user by other means. The user may apply the suggested corrections by processor 404 manually using user interface 407. In another embodiment, the corrections may be presented to the user on display 406 and directly applied to secondary wellbore 170 by means of control signals provided to a steering system being used to steer the drill bit 210 in the wellbore 170 being drilled.

[0057] A delay may be present between displaying on display 406 the correction determined by processor 404 and the application of the correction instructions to secondary wellbore 170. During the delay, a user may interrupt the execution of the determined corrections or may edit the corrections before execution. In another embodiment, the entire process of determining the corrections by processor 404 and the

execution of the determined corrections on secondary wellbore 170 may be completely automated without human involvement.

5 [0058] The process of SAGD ranging (or ranging for other drilling operations) using fiber Bragg grating sensors is advantageous over using magnetic ranging devices. In many cases, fiber Bragg sensors will be installed for other reasons. Therefore, the use of fiber Bragg sensors for ranging may not require any additional hardware (other than a suitably configured processor 404). Also, wellbore ranging using fiber Bragg grating sensors does not require use of non-conventional bottom hole assemblies for drilling.

10 [0059] In one embodiment of the invention, the secondary wellbore may be drilled in close proximity and precise coplanar alignment to the primary wellbore using conventional drilling BHA and conventional practices including a drill bit, a mud motor (or mud/air hammer, or mud turbine), and a MWD tool or other drilling devices as known in the industry such as rotary steerable system for example. Figure 4 schematically shows various noise source generators during the operation of the drill in the secondary wellbore, 15 that are received by the fiber Bragg gratings within horizontal section 110A of primary wellbore 110. Noise can be generated from drill bit 210. Noise may also be generated from BHA 200, which may include various acoustic sources (not shown). Additionally, noise may be generated using an independent acoustic signal generator 600 coupled to BHA 200. Figures 5A-5D schematically show how several key components of BHA 200 20 may generate a large amount of acoustic or seismic noise. In general, the locations of acoustic sources within BHA 200 are known as the acoustic signatures (e.g. frequency spectra, dominant frequencies, etc.) of the sound emitted by these acoustic sources.

[0060] Figure 5A shows how the drill bit 210 interface with the formation 120 may generate noise and vibration (dashed lines) during drilling causing micro seismic activity 25 within the formation. This noise can be characterised and its signature can be monitored by the fiber Bragg gratings as described above.

[0061] Figure 5B shows how the mud motor (or mud/air hammer, or mud turbine) 510, which is essentially a cavitation pump, may generate an acoustic harmonic frequency in

the drilling fluid due to its mechanical operation. This noise can be characterised and its signature can be monitored by the fiber Bragg gratings as described above.

5 [0062] Figure 5C shows how the MWD tool 520 may be a mud pulser, where its main form of telemetry to surface may be by restricted drilling fluid flow pressure pulses, the fluid pressure pulses are an acoustic wave that travels through the drilling fluid. These pulses may be random pulses as required for coding of information for telemetry to surface, or specifically controlled pulse sequences to generate a known acoustic signature. This noise can be characterised and its signature can be monitored by the fiber Bragg gratings as described above.

10 [0063] Figure 5C also shows how the MWD tool 520 could be an Acoustic Telemetry MWD system, which by its nature emits an acoustic signal as its means of telemetry to surface. These could be acoustic waves generated as required for coding of information for telemetry to the surface, or specifically controlled acoustic wave sequences to generate a known acoustic signature. This noise can be characterised and its signature can be
15 monitored by the fiber Bragg gratings as described above.

[0064] In addition to the above mentioned conventional drilling BHA components, an agitator may be used as a noise generating device. Agitators may be provided in a BHA used for directional drilling. An agitator can provide a vibration source in the BHA that will break the friction of the drill pipe and the wellbore during horizontal drilling. This
20 may permit extended reach of the drill bit. This vibration noise and micro seismic activity can be characterised and its signature can be monitored by the fiber Bragg gratings as described above.

[0065] In another embodiment as shown in Figure 5D, the wellbore may be drilled using a modified BHA where an additional “low energy, continuous frequency noise source” 530
25 is directly coupled to the drill bit as a component of the bottom hole assembly, such as a collar or sub. This low energy, continuous frequency noise source could be any number of devices specifically designed to generate noise. For example, it could be a pure mechanical drilling fluid propelled cam shaft vibrator/impactor that emits a known low energy continuous frequency noise, or a pure mechanical fluid flow activated poppet

orifice fluid pressure pulse generator, or other specifically designed mechanical or electro-mechanical device to generate a known and controllable noise.

[0066] It is apparent that a wide range of acoustic sources associated with drilling a well bore may be tracked using fiber Bragg sensor arrays. It is advantageous that at least some of the acoustic sources be controlled and continuous acoustic sources that produce sound having a known and easily distinguishable acoustic signature. Examples of such acoustic sources are controlled MWD pulse patterns and specifically designed acoustic generators integrated into the BHA.

[0067] The speed of sound in geological formations depends on the local characteristics of the formations through which the sound is propagating. This could lead to errors, especially in time of flight related measurements. Fortunately, in many practical applications the geological formations in which multiple wellbores are desired are fairly uniform in acoustic characteristics on the scale of the wellbores. In some embodiments of the invention, the acoustic noise generator and the fiber Bragg grating sensors may be located in the same geological formation or in geological formations having substantially similar characteristics. In such cases, time of flight related measurements may be more accurate than they would be in the case of acoustic propagation through formations having markedly different acoustic transmission properties since the acoustic noise, generated by any number of non-limited methods (controlled or random noise), travels through the same formation or substantially the same formation before arriving at the fiber Bragg grating sensors.

[0068] Figure 6 schematically shows another embodiment of the invention where one or more fiber Bragg grating sensor lines 700 are placed at or near the surface. For example, fiber Bragg grating sensor line 700 may be buried in a trench, laid on the surface or attached to the surface by affixing means such as spikes, rods or other means. Surface sensor line 700 can be used in addition to or instead of other fiber Bragg grating sensor lines. Surface sensor line 700 may be advantageous in getting better position information for wellbores especially for drilling the first few boreholes in a formation. Surface sensor line(s) 700 may be surveyed in place to provide additional information for accurate placement of wellbores relative to survey coordinates.

[0069] In this embodiment, the acoustic noise, generated by any number of non-limited methods (controlled or random noise), may travel through the different formations between the noise generation source and the fiber Bragg grating sensor line 700 near the surface and impart an acoustic signature on fiber Bragg grating sensor line 700. Errors in
5 time of flight related measurements contributed to change in the speed of sound/seismic/acoustic travel by traveling through various formations of different and inconsistent densities may be accounted for by using known properties of the formations and formation profiles obtained from surveys such as resistivity logs, gamma logs, etc. Computations to correct for perturbations in the received signal may be made based on
10 depth, geometry and nature of formations and proper corrective algorithms may be applied.

[0070] In other embodiments, Horizontal section 110A in primary wellbore 110 may be equipped with an acoustic signature generating device and BHA 200 in secondary wellbore 170 may comprise a ranging device.

15 [0071] In addition to use as described herein, installed fiber Bragg sensor lines may be used for measuring temperature along the length of wellbores, measuring the inflow of hydrocarbon at discrete points along the length of the wellbores, and/or for determining the effectiveness of injected steam. Fiber Bragg grating sensor lines may be used for monitoring and measuring various characteristics of a producing well (such as pressures,
20 temperatures, seismic, and inline flow measurements), for wellbore performance and production monitoring as well as SAGD life cycle characterization.

[0072] Certain implementations of the invention comprise computer processors which execute software instructions which cause the processors to perform a method of the invention. For example, one or more processors in a directional drilling system may
25 implement the methods described herein by executing software instructions in a program memory accessible to the processors. The invention may also be provided in the form of a program product. The program product may comprise any tangible medium which carries a set of computer-readable signals comprising instructions which, when executed by a data processor, cause the data processor to execute a method of the invention. Program
30 products according to the invention may be in any of a wide variety of forms. The

program product may comprise, for example, physical media such as magnetic data storage media including floppy diskettes, hard disk drives, optical data storage media including CD ROMs, DVDs, electronic data storage media including ROMs, PROMs, EPROMs, flash RAM, or the like. The computer-readable signals on the program product
 5 may optionally be compressed or encrypted.

Interpretation of Terms

[0073] Unless the context clearly requires otherwise, throughout the description and the claims:

- 10 • "comprise," "comprising," and the like are to be construed in an inclusive sense, as opposed to an exclusive or exhaustive sense; that is to say, in the sense of "including, but not limited to" .
- "connected," "coupled," or any variant thereof, means any connection or coupling, either direct or indirect, between two or more elements; the coupling or connection between the elements can be physical, logical, or a combination thereof.
- 15 • "herein," "above," "below," and words of similar import, when used to describe this specification shall refer to this specification as a whole and not to any particular portions of this specification.
- "or," in reference to a list of two or more items, covers all of the following interpretations of the word: any of the items in the list, all of the items in the list, and any combination of the items in the list.
- 20 • the singular forms "a", "an" and "the" also include the meaning of any appropriate plural forms.

[0074] Words that indicate directions such as "vertical", "transverse", "horizontal",
 25 "upward", "downward", "forward", "backward", "inward", "outward", "vertical", "transverse", "left", "right", "front", "back", "top", "bottom", "below", "above", "under", and the like, used in this description and any accompanying claims (where present) depend on the specific orientation of the apparatus described and illustrated. The subject matter described herein may assume various alternative orientations. Accordingly, these
 30 directional terms are not strictly defined and should not be interpreted narrowly.

[0075] Where a component (e.g. a circuit, module, assembly, device, drill string component, drill rig system etc.) is referred to above, unless otherwise indicated, reference to that component (including a reference to a "means") should be interpreted as including as equivalents of that component any component which performs the function of the described component (i.e., that is functionally equivalent), including components which are not structurally equivalent to the disclosed structure which performs the function in the illustrated exemplary embodiments of the invention.

[0076] Specific examples of systems, methods and apparatus have been described herein for purposes of illustration. These are only examples. The technology provided herein can be applied to systems other than the example systems described above. Many alterations, modifications, additions, omissions and permutations are possible within the practice of this invention. This invention includes variations on described embodiments that would be apparent to the skilled addressee, including variations obtained by: replacing features, elements and/or acts with equivalent features, elements and/or acts; mixing and matching of features, elements and/or acts from different embodiments; combining features, elements and/or acts from embodiments as described herein with features, elements and/or acts of other technology; and/or omitting combining features, elements and/or acts from described embodiments.

[0077] It is therefore intended that the following appended claims and claims hereafter introduced are interpreted to include all such modifications, permutations, additions, omissions and sub-combinations as may reasonably be inferred. The scope of the claims should not be limited by the preferred embodiments set forth in the examples, but should be given the broadest interpretation consistent with the description as a whole.

WHAT IS CLAIMED IS:

1. A method of drilling two or more wellbores in close proximity to one another, the method comprising:
 - drilling a primary wellbore;
 - 5 equipping the primary wellbore with an optical fiber comprising fiber Bragg grating sensors at spaced apart locations along a length of the primary wellbore;
 - drilling at least one secondary wellbore using a directional drill and, while drilling the least one secondary wellbore determining a location of the least one
 - 10 secondary wellbore relative to the primary wellbore by, at least in part, detecting acoustic signals at the fiber Bragg grating sensors and processing the detected acoustic signals.
2. A method according to claim 1 comprising generating course corrections for the
- 15 least one secondary wellbore based on the determined location of the least one secondary wellbore and applying the course corrections to steer the directional drill.
3. A method according to claim 2 wherein the course corrections are applied
- 20 manually by a user.
4. A method according to claim 1 wherein the directional drill comprises a drill string and a bottom hole assembly BHA located at a downhole end of the drill string and the bottom hole assembly comprises an acoustic source.
- 25
5. A method according to claim 1, wherein the primary wellbore and the at least one secondary wellbore are Steam Assisted Gravity Drainage (SAGD) wellbore pairs.
6. A method according to claim 2, wherein the course corrections are applied to
- 30 maintain coplanar alignment between the primary wellbore and the at least one secondary wellbore.

7. A method according to claim 6 wherein the course corrections are automatically applied by a processor/controller in communication with the directional drill.
8. A method according to claim 1, wherein the primary wellbore is placed in a formation and the at least one secondary wellbore is located in the same formation.
9. A method according to claim 1 wherein detecting the acoustic signals comprises interrogating the fiber Bragg grating sensors using optical sensor processing equipment comprising a light source and signal analysis equipment, wherein the light source provides an optical signal to the optical fiber and the signal analysis equipment monitors frequency shifts in light reflected by the fiber Bragg grating sensors.
10. A method according to claim 4, wherein the BHA comprises a drill bit, the drill bit interfaces with a formation during the drilling operation and serves as the acoustic source.
11. A method according to claim 4, wherein the BHA comprises a mud motor and the mud motor serves as the acoustic source.
12. A method according to claim 4, wherein the BHA comprises a mud pulser and the mud pulser serves as the acoustic source.
13. A method according to claim 4, wherein the BHA comprises an agitator and the agitator serves as the acoustic source.
14. A method according to claim 4, wherein the BHA comprises a continuous frequency noise source directly coupled to a drill bit.
15. A computer program product comprising a computer readable memory storing computer executable instructions thereon that when executed by a computer cause the computer to process signals representing acoustic emissions from drilling picked up at an array of fiber Bragg grating sensors disposed within a primary

wellbore to determine distances between the fiber Bragg grating sensors and one or more sources of the acoustic emissions.

16. A computer program product according to claim 15, comprising determining a position of the one or more sources of acoustic emissions by reverse triangulation.
17. A computer program product according to claim 15 wherein the computer executable instructions, when executed, cause the computer to process the signals to extract a plurality of acoustic components from the signals.
18. A computer program product according to claim 17 wherein the one or more sources of the acoustic emissions comprises a plurality of distinct acoustic sources.
19. A computer program product according to claim 18 wherein the computer executable instructions, when executed, causes the computer to associate different ones of the plurality of acoustic components with corresponding ones of the plurality of distinct acoustic sources.
20. A computer program product according claim 15 wherein the computer executable instructions, when executed, cause the computer to process signals representing acoustic emissions from drilling picked up at an additional plurality of linear arrays of additional fiber Bragg gating sensors disposed within additional multiple wellbores to determine distances between the fiber Bragg grating sensors, the additional fiber Bragg grating sensors and the one or more sources of the acoustic emissions.
21. A computer program product according to claim 20 wherein the one or more sources of the acoustic emissions comprises a plurality of distinct acoustic sources.
22. An apparatus for downhole wellbore placement during drilling, the apparatus comprising a processor for receiving signals representing acoustic emissions from drilling picked up at a linear array of fiber Bragg grating sensors disposed within a primary wellbore, the processor processing the received signals to determine

distances between the fiber Bragg grating sensors and one or more sources of the acoustic emissions, the one or more sources of the acoustic emissions disposed within at least one secondary wellbore being drilled using a directional drill.

- 5 23. An apparatus according to claim 22 wherein the processor comprises:
 a light source;
 an optical coupler; and
 signal analysis equipment,
 wherein the light source provides an optical signal to the optical coupler,
10 the optical coupler provides the optical signal to the fiber Bragg grating sensors
 and also provides returned optical signals from the fiber Bragg grating sensors to
 the signal analysis equipment and the signal analysis equipment monitors
 frequency shifts in the returned optical signals.
- 15 24. An apparatus according to claim 23 wherein the acoustic emissions apply strain on
 the fiber Bragg grating sensors causing a wavelength shift in a central wavelength
 of the returned optical signal reflected by the fiber Bragg grating sensors.
- 20 25. An apparatus according to claim 23 wherein the signal analysis equipment
 comprises:
 a wavelength selective filter;
 phase discrimination equipment; and
 a processor/controller,
 wherein the wavelength selective filter separates the returned optical signal
25 to a respective optical signal for each respective sensor of the fiber Bragg grating
 sensors, the phase discrimination equipment receive each of the respective optical
 signals and generate information by demodulating and performing phase
 discrimination on each of the respective optical signals, and the
 processor/controller processes the information to provide course corrections to the
30 directional drill while drilling the at least one secondary wellbore.
26. An apparatus according to claims 25 wherein the processor/controller is configured
 to determine the course corrections using reverse triangulation.

27. An apparatus according to claim 25 wherein the processor/controller is configured to automatically apply the course corrections to the directional drill.
- 5 28. An apparatus according to claim 25 wherein the processor comprises a display and the processor /controller displays the course corrections on the display.
29. An apparatus according to claim 28 wherein the processor comprises a user interface for a user to manually input the course corrections to the directional drill.
- 10 30. An apparatus according to claim 22 wherein the directional drill comprises a drill string and a bottom hole assembly BHA located at a downhole end of the drill string and the BHA comprises the one or more sources of the acoustic emissions.
- 15 31. An apparatus according to claim 30 wherein the BHA comprises a drill bit, the drill bit interfaces with a formation during the drilling operation and serves as the one or more sources of the acoustic emissions.
32. An apparatus according to claim 30, wherein the BHA comprises a mud motor and the mud motor serves as the one or more sources of the acoustic emissions.
- 20 33. An apparatus according to claim 30, wherein the BHA comprises a mud pulser and the mud pulser serves as the one or more sources of the acoustic emissions.
- 25 34. An apparatus according to claim 30, wherein the BHA comprises an agitator and the agitator serves as the one or more sources of the acoustic emissions.
35. An apparatus according to claim 30, wherein the BHA comprises a continuous frequency noise source directly coupled to a drill bit in the BHA.
- 30 36. An apparatus according to claim 22 wherein the processor processes the received signals to extract a plurality of acoustic components from the signals.

37. An apparatus according to claim 36 wherein the one or more sources of the acoustic emissions comprises a plurality of distinct acoustic sources.
38. An apparatus according to claim 22, wherein the processor receives signals
5 representing acoustic emissions from drilling picked up at an additional plurality of linear array of additional fiber Bragg grating sensors disposed within additional multiple wellbores, the processor processing the received signals to determine distances between the fiber Bragg grating sensors, the additional fiber Bragg grating sensors and the one or more sources of the acoustic emissions.
10
39. An apparatus according to claim 38 wherein the one or more sources of acoustic emissions comprises a plurality of distinct acoustic sources.

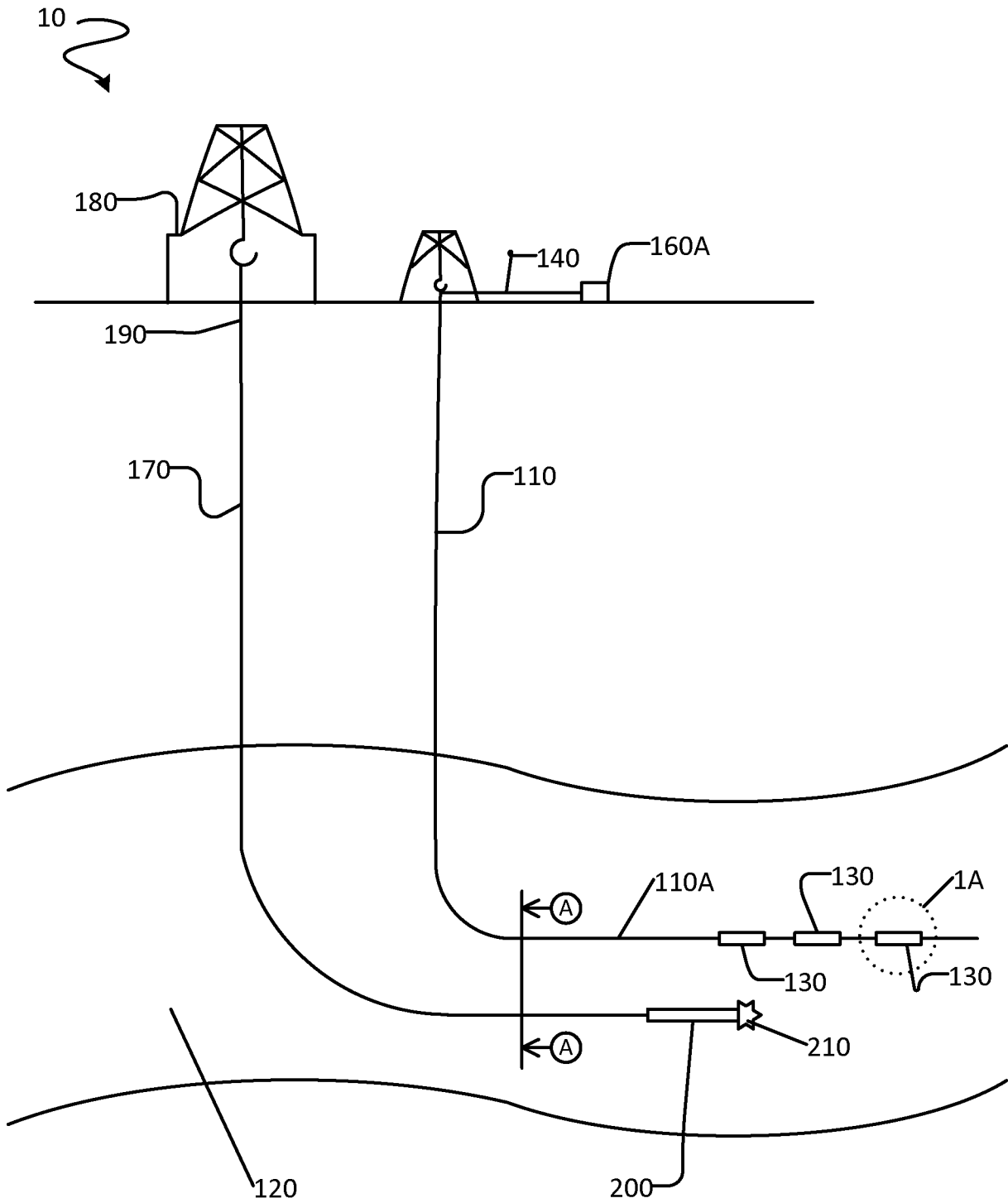


FIG. 1

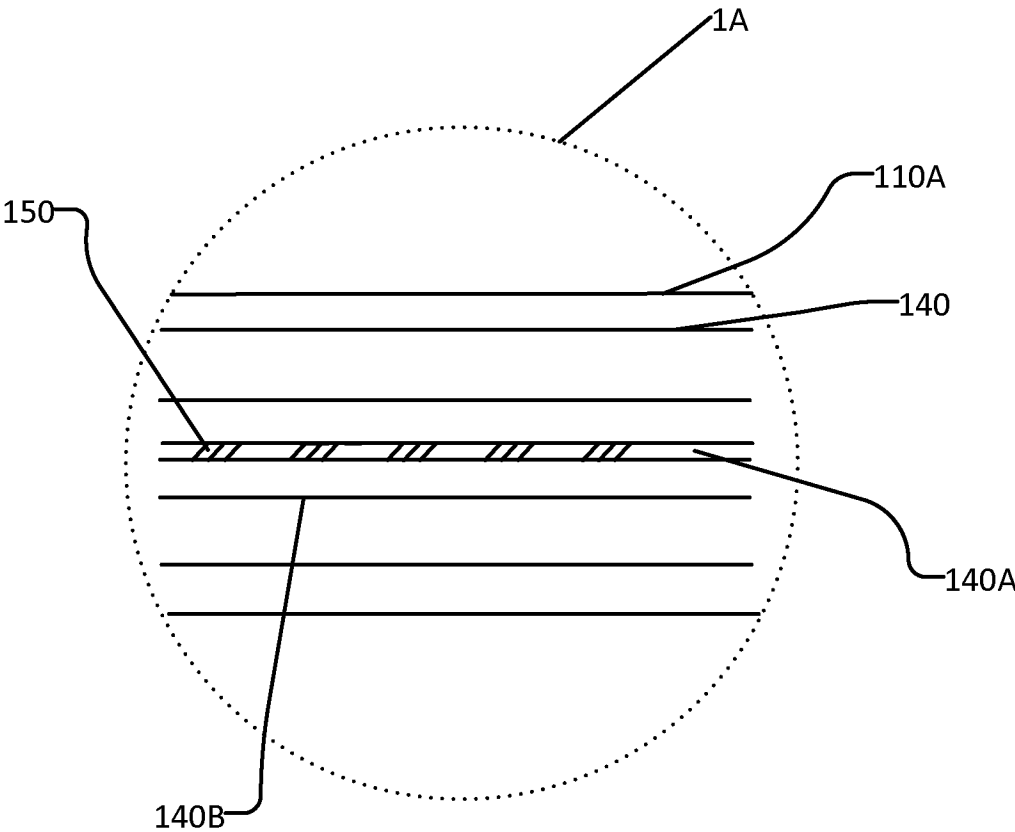


FIG. 1A

3/11

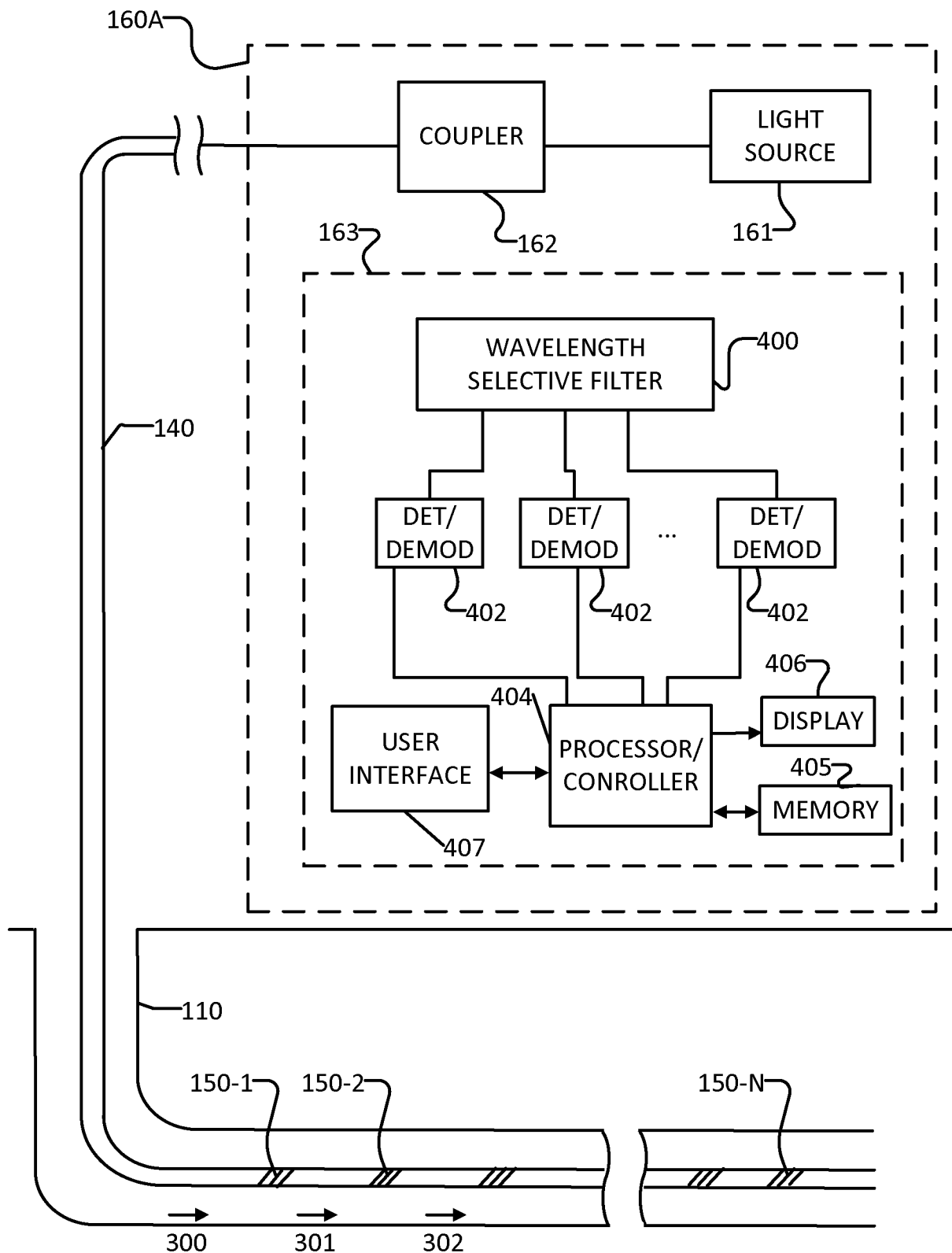


FIG. 1B

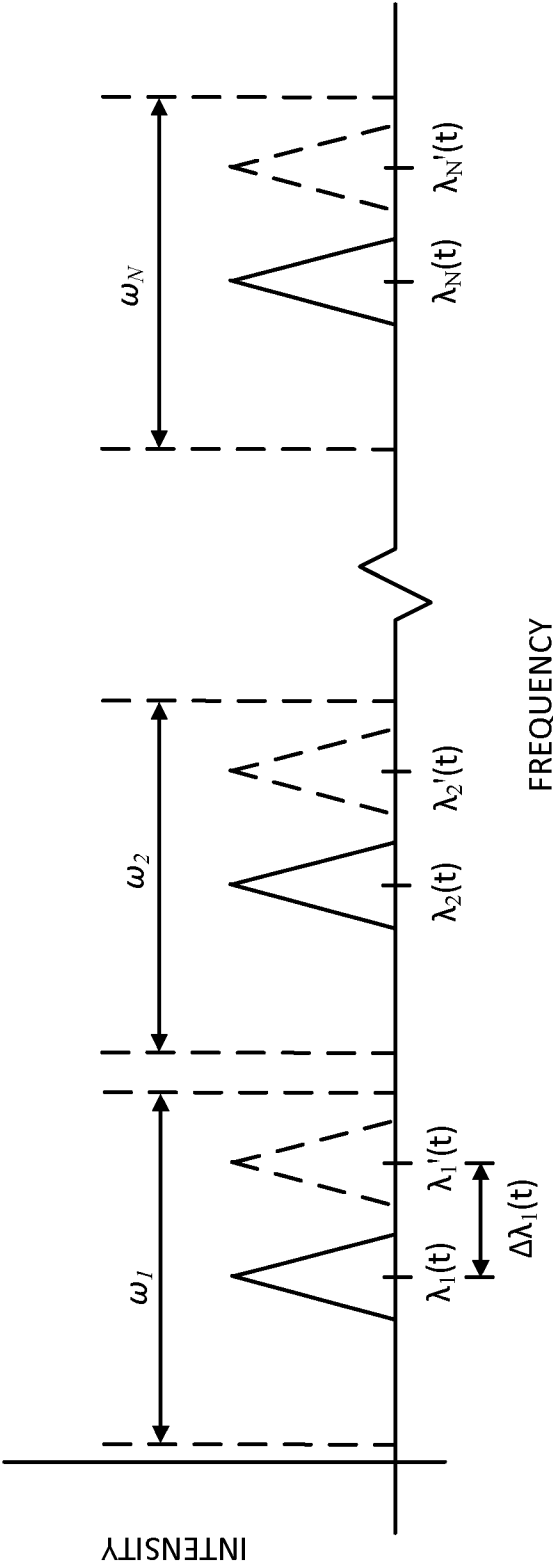


FIG. 1C

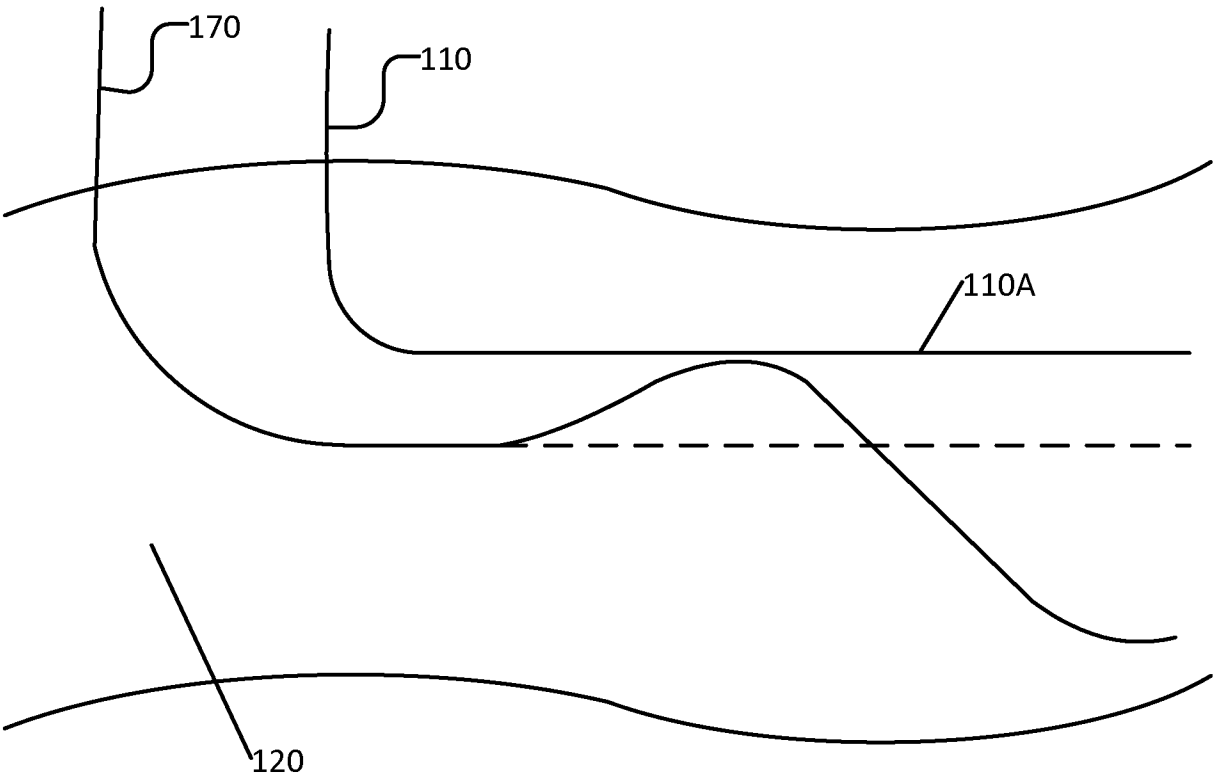


FIG. 2

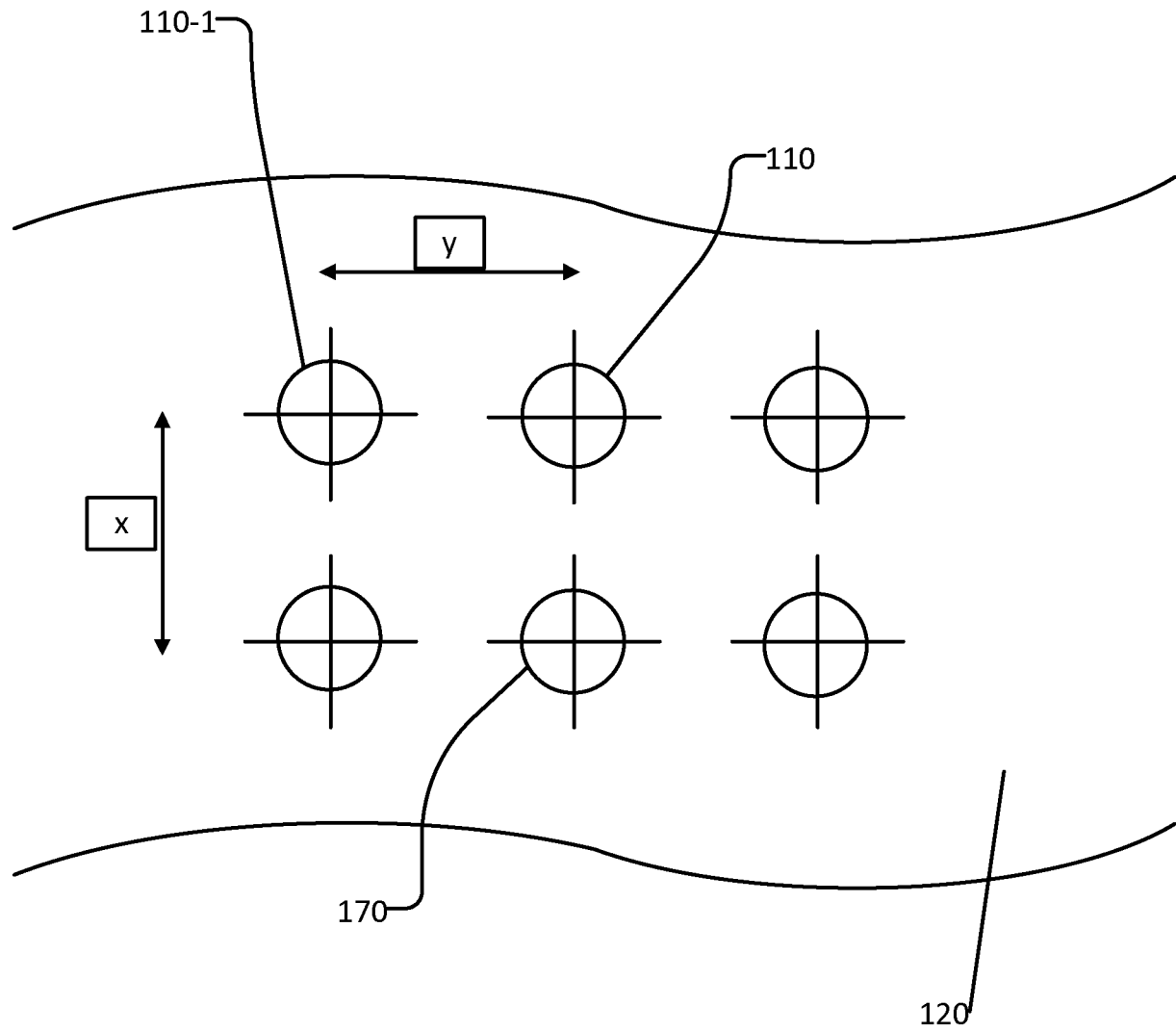


FIG. 3

7/11

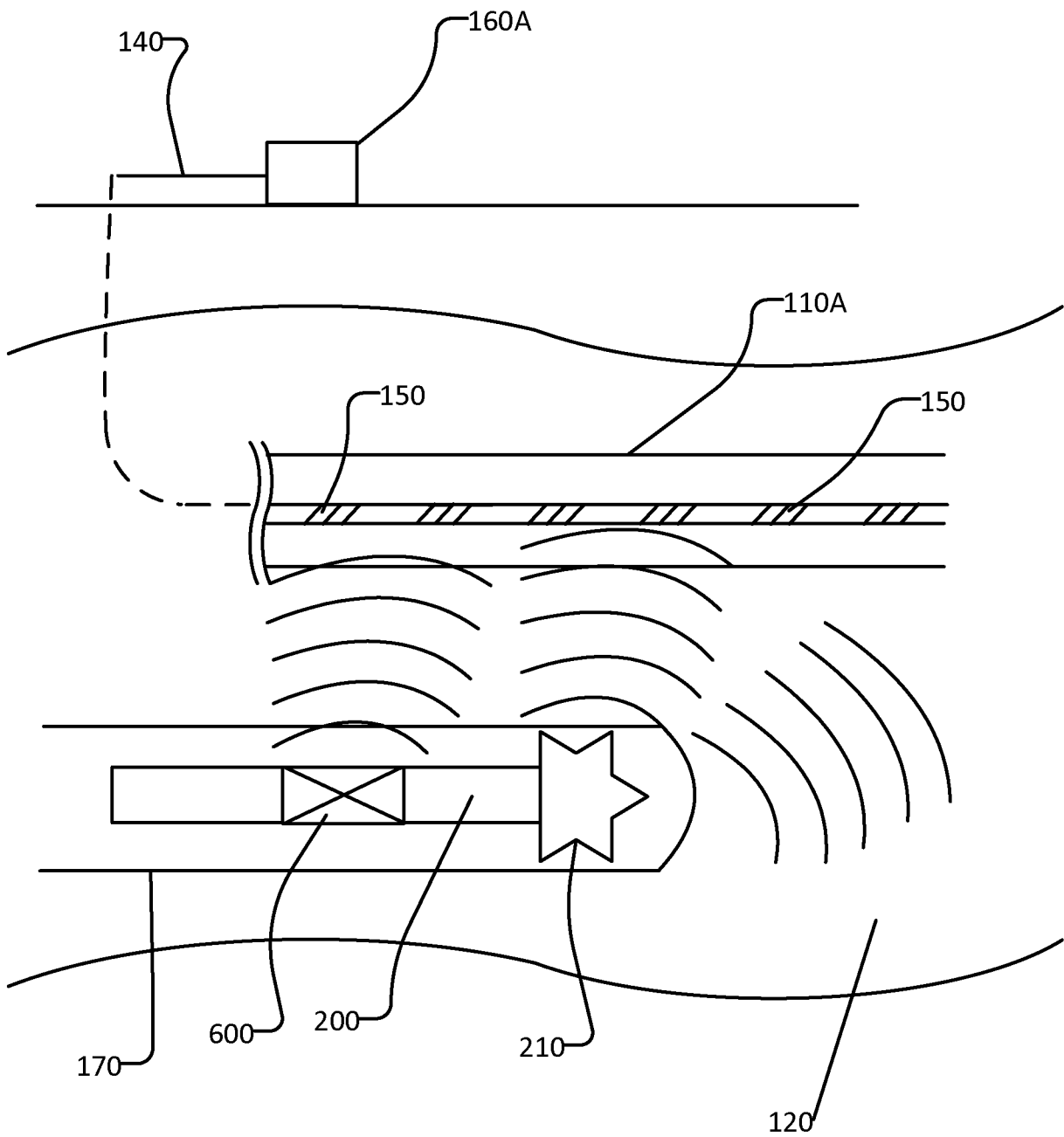


FIG. 4

8/11

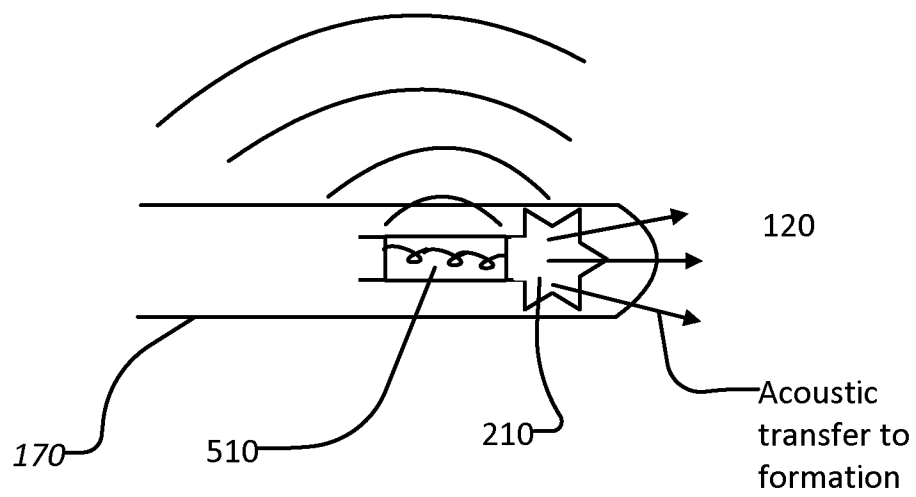
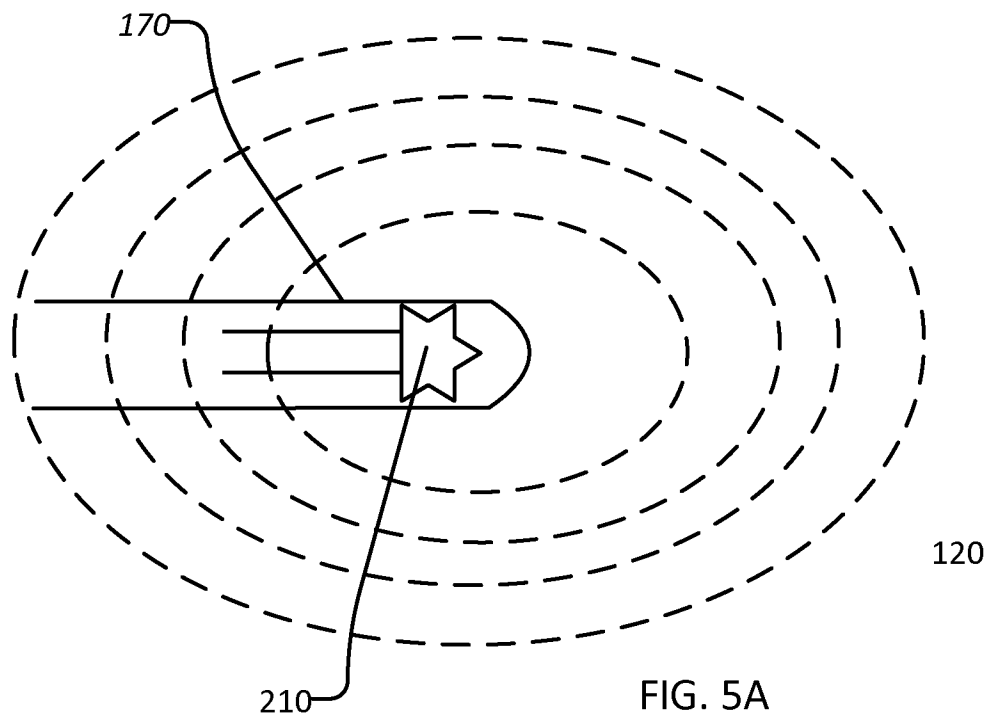


FIG. 5B

9/11

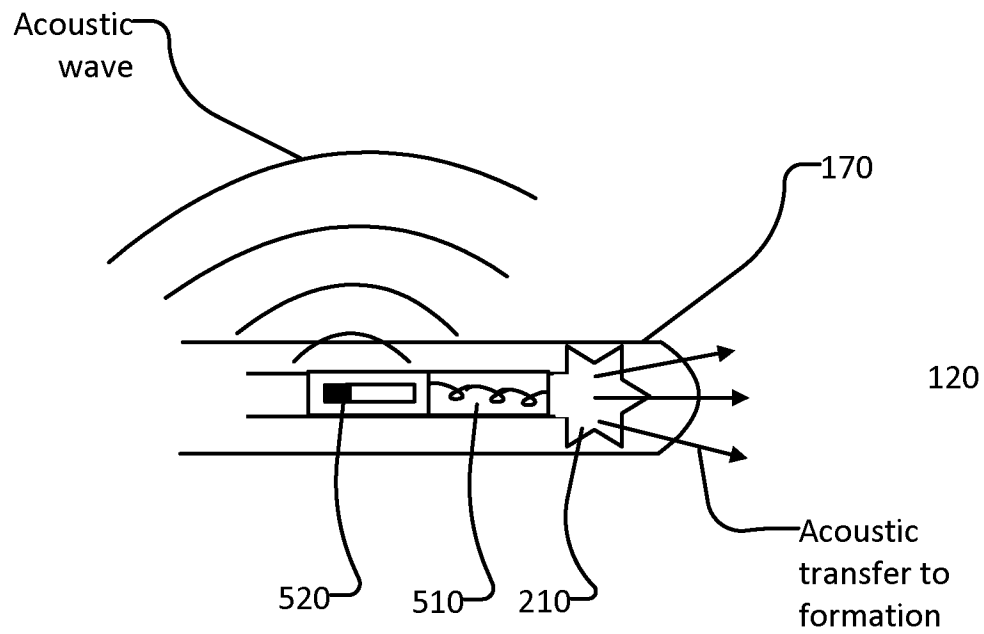


FIG. 5C

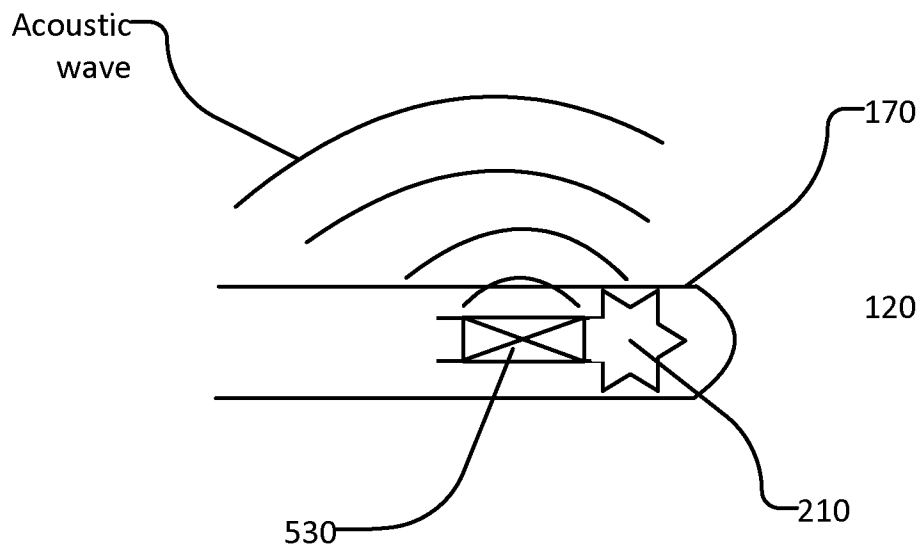


FIG. 5D

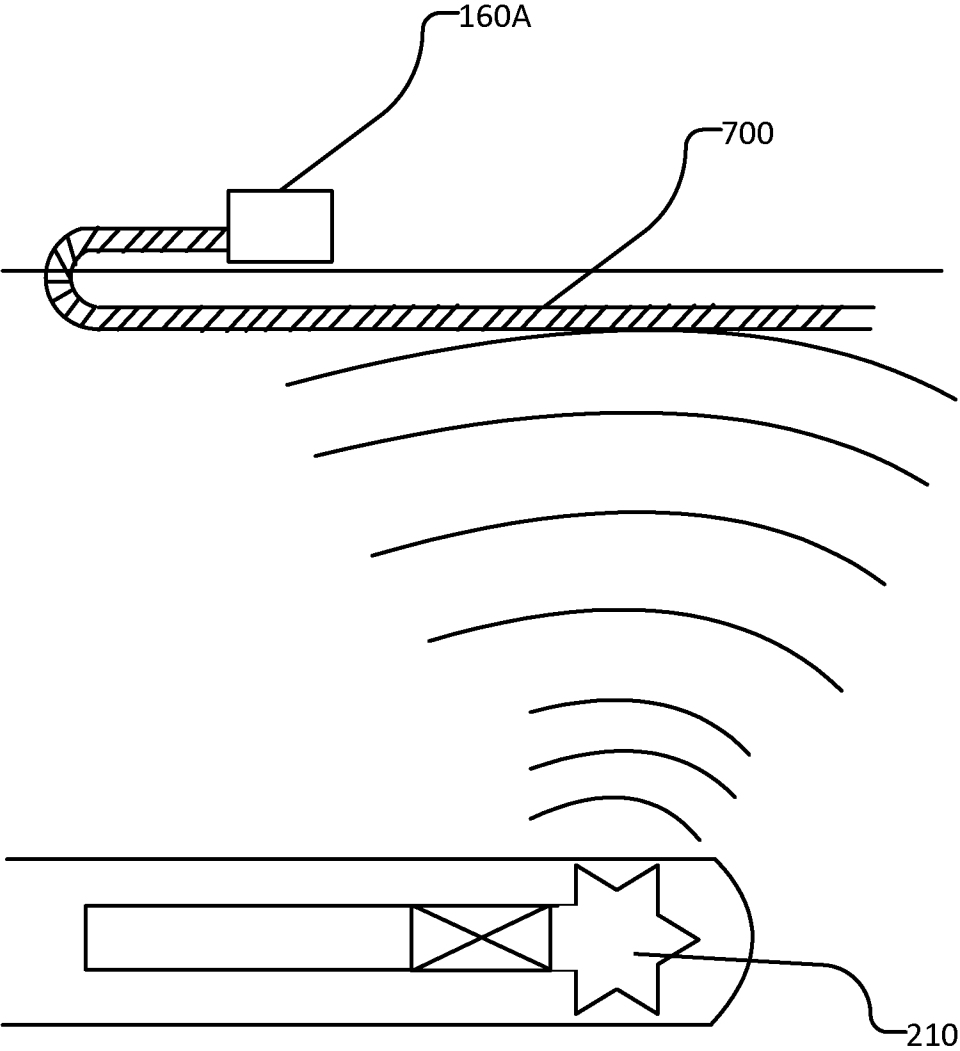


FIGURE 6

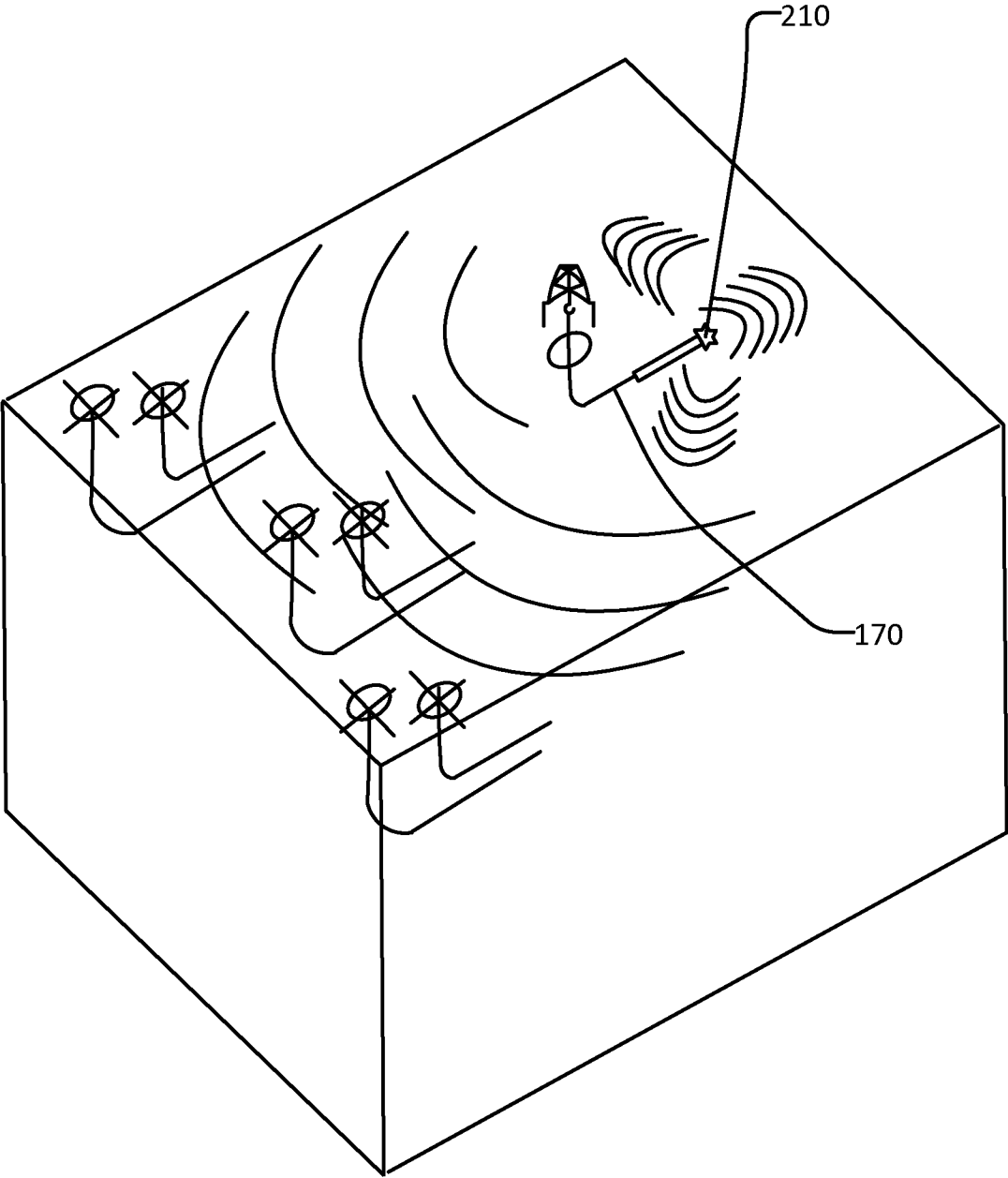


FIG. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/CA2013/050374

A. CLASSIFICATION OF SUBJECT MATTER

IPC: **E21B 44/00** (2006.01) , **E21B 43/24** (2006.01) , **E21B 43/30** (2006.01) , **E21B 47/09** (2012.01) , **E21B 47/135** (2012.01) , **E21B 7/00** (2006.01) , (**E21B 7/04** (2006.01))

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)

IPC(2006.01): E21B

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

Electronic database(s) consulted during the international search (name of database(s) and, where practicable, search terms used)

TotalPatent, Canadian Patents Database

keywords: fiber or fibre, Bragg, acoustic, location, secondary or multiple or two, sensor, placement

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	WO2012/067611A1 (HAY, R. et al.) 24 May 2012 (24-05-2012) *pages 3, 7, 8, 11-16; Fig. 10*	1-14 and 22-39
Y	WO2009/146548A1 (HOLMEN, G. et al.) 10 December 2009 (10-12-2009) *pages 19,31, 32; Fig. 5*	1-14 and 22-39
Y	US2010/0284250A1 (CORNISH, B. et al.) 11 November 2010 (11-11-2010) *paragraphs [0009]-[0023]*	1-14 and 22-39
X	WO02/057805A2 (TUBEL, P.) 25 July 2002 (25-07-2002)	15-21
Y	*paragraphs [0020]-[0022], [0027], [0046]-[0050], [0068]-[0070], [0094], [00111]; claims 1, 4, 5, 9, 11, and 16*	1-14 and 22-39

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

☒ See patent family annex.

* Special categories of cited documents :	"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
"A" document defining the general state of the art which is not considered to be of particular relevance	"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
"E" earlier application or patent but published on or after the international filing date	"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
"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)	"&" document member of the same patent family
"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	

Date of the actual completion of the international search

12 August 2013 (12-08-2013)

Date of mailing of the international search report

05 December 2013 (05-12-2013)

Name and mailing address of the ISA/CA
Canadian Intellectual Property Office
Place du Portage I, C114 - 1st Floor, Box PCT
50 Victoria Street
Gatineau, Quebec K1A 0C9
Facsimile No.: 001-819-953-2476

Authorized officer

Chau Tran (819) 934-3421

INTERNATIONAL SEARCH REPORT
Information on patent family members

International application No.
PCT/CA2013/050374

Patent Document Cited in Search Report	Publication Date	Patent Family Member(s)	Publication Date
WO2012067611A1	24 May 2012 (24-05-2012)	AU2010363968A1 CA2813729A1	02 May 2013 (02-05-2013) 24 May 2012 (24-05-2012)
WO2009146548A1	10 December 2009 (10-12-2009)	CA2746078A1	10 December 2009 (10-12-2009)
US2010284250A1	11 November 2010 (11-11-2010)	WO2009073008A1	11 June 2009 (11-06-2009)
WO02057805A2	25 July 2002 (25-07-2002)	AU2002246492A1 CA2412041A1 GB0229852D0 GB2383633A US2003094281A1 US6913079B2 WO02057805A3 WO02057805B1	30 July 2002 (30-07-2002) 25 July 2002 (25-07-2002) 29 January 2003 (29-01-2003) 02 July 2003 (02-07-2003) 22 May 2003 (22-05-2003) 05 July 2005 (05-07-2005) 17 October 2002 (17-10-2002) 06 March 2003 (06-03-2003)