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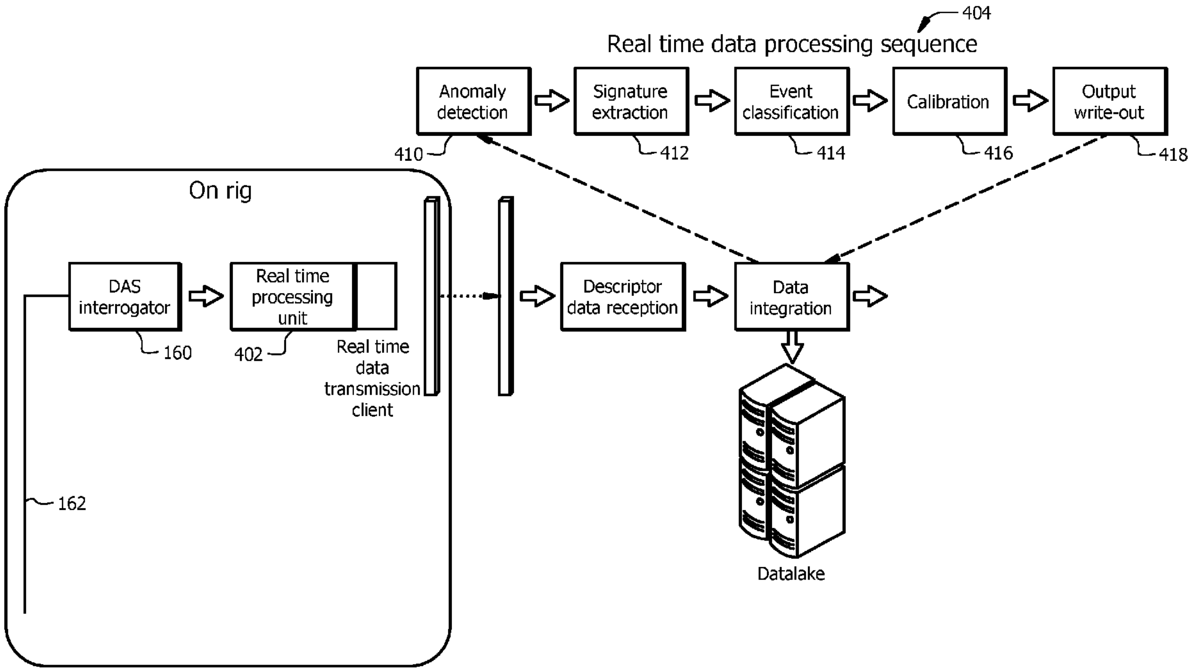

FIG. 5

(57) Abstract: A method of calibrating a distributed acoustic sensor (DAS) system includes obtaining a backscattered optical signal from a fiber optic cable disposed within a wellbore, determining an origination point within the backscattered optical signal, determining a bottom point within the backscattered optical signal, correlating the origination point and the bottom point with physical depth information for the wellbore, and determining at least a depth calibration for the backscattered optical signal using the correlating. The backscattered optical signal is representative of an acoustic or thermal signal along the fiber optic cable. The origination point identifies a first location at an upper point of the fiber optic cable within the backscattered optical signal, and the bottom point identifies a second location at a lower point of the fiber optic cable within the wellbore. The depth calibration correlates a sensed depth within the backscattered optical signal with a physical depth within the wellbore.

WO 2021/037586 A1

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DEPTH CALIBRATION FOR DISTRIBUTED ACOUSTIC SENSORS

BACKGROUND

[0001] Within a hydrocarbon production well, various fluids such as hydrocarbons, water, gas, and the like can be produced from the formation into the wellbore. The production of the fluid can result in the movement of the fluids in various downhole regions, including with the subterranean formation, from the formation into the wellbore, and within the wellbore itself.

BRIEF SUMMARY OF THE DISCLOSURE

[0002] In some embodiments, a method of calibrating a distributed acoustic sensor (DAS) system includes obtaining a backscattered optical signal from a fibre optic cable disposed within a wellbore, determining an origination point within the backscattered optical signal, determining a bottom point within the backscattered optical signal, correlating the origination point and the bottom point with physical depth information for the wellbore, and determining at least a depth calibration for the backscattered optical signal using the correlating. The backscattered optical signal is representative of an acoustic and/or thermal signal along the fibre optic cable. The origination point identifies a first location at an upper point of the fibre optic cable within the backscattered optical signal, and the bottom point identifies a second location at a lower point of the fibre optic cable within the wellbore. The depth calibration correlates a sensed depth within the backscattered optical signal with a physical depth within the wellbore.

[0003] In some embodiments, a system for providing a depth calibration for an acoustic monitoring system comprises a processor and a memory. The memory comprises a depth calibration application that, when executed on the processor, configures the processor to: receive an acoustic signal from the acoustic monitoring system disposed within a wellbore, determine an origination point within the acoustic signal, determine a bottom point within the acoustic signal, receive physical depth information for the wellbore, correlate the origination point and the bottom point with the physical depth information for the wellbore, and determine a depth calibration for the acoustic signal using the correlating. The acoustic signal is representative of an acoustic signal along the length of the wellbore. The origination point identifies a first location at an upper point of the acoustic monitoring within the acoustic signal, and the bottom point identifies a second location at a lower point of the acoustic monitoring system within the wellbore. The depth calibration correlates a sensed depth within the acoustic signal with a physical depth within the wellbore.

[0004] These and other features will be more clearly understood from the following detailed description taken in conjunction with the accompanying drawings and claims.

[0005] Embodiments described herein comprise a combination of features and advantages intended to address various shortcomings associated with certain prior devices, systems, and methods. The foregoing has outlined rather broadly the features and technical advantages of the invention in order that the detailed description of the invention that follows may be better understood. The various characteristics described above, as well as other features, will be readily apparent to those skilled in the art upon reading the following detailed description, and by referring to the accompanying drawings. It should be appreciated by those skilled in the art that the conception and the specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the invention. It should also be realized by those skilled in the art that such equivalent constructions do not depart from the spirit and scope of the invention as set forth in the appended claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0006] For a detailed description of the preferred embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0007] Figure 1 is a schematic, cross-sectional illustration of a downhole wellbore environment according to an embodiment.

[0008] Figure 2 is a schematic view of an embodiment of a wellbore tubular with fluid ingress according to an embodiment.

[0009] Figures 3A and 3B are a schematic, cross-sectional views of embodiments of a well with a wellbore tubular having an optical fibre associated therewith.

[0010] Figures 4A and 4B are schematic views of embodiments of a wellbore tubular having an optical fibre associated therewith.

[0011] Figure 5 illustrates an embodiment of a schematic processing flow for an acoustic signal.

[0012] Figures 6A and 6B illustrate exemplary acoustic depth-time block graphs.

[0013] Figures 7A, 7B, and 7C illustrate exemplary filtered acoustic depth-time graphs.

[0014] Figure 8 schematically illustrates a computer that can be used to carry out various steps according to some embodiments.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0015] Unless otherwise specified, any use of any form of the terms “connect,” “engage,” “couple,” “attach,” or any other term describing an interaction between elements is not meant to limit the interaction to direct interaction between the elements and may also include indirect interaction between the elements described. In the following discussion and in the claims, the terms “including” and “comprising” are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to . . . “. Reference to up or down will be made for purposes of description with “up,” “upper,” “upward,” “upstream,” or “above” meaning toward the surface of the wellbore and with “down,” “lower,” “downward,” “downstream,” or “below” meaning toward the terminal end of the well, regardless of the wellbore orientation. Reference to inner or outer will be made for purposes of description with “in,” “inner,” or “inward” meaning towards the central longitudinal axis of the wellbore and/or wellbore tubular, and “out,” “outer,” or “outward” meaning towards the wellbore wall. As used herein, the term “longitudinal” or “longitudinally” refers to an axis substantially aligned with the central axis of the wellbore tubular, and “radial” or “radially” refer to a direction perpendicular to the longitudinal axis. The various characteristics mentioned above, as well as other features and characteristics described in more detail below, will be readily apparent to those skilled in the art with the aid of this disclosure upon reading the following detailed description of the embodiments, and by referring to the accompanying drawings.

[0016] Disclosed herein is a real time signal processing architecture and method that allows for the calibration of a distributed acoustic sensor (DAS) and/or distributed temperature sensor (DTS) system. While referred to as a DAS system herein, the system can be used for DAS, DTS, or a combination of both DAS and DTS. In some examples, the DAS system facilitates identification of various downhole events including leak detection, pressure source identification, flow path identification, and phase detection of a leaking fluid in the wellbore (within a casing, within an annulus, etc.), the formation (e.g., overburden monitoring, etc.), or moving between the formation and wellbore. As used herein, the term “real time” refers to a time that takes into account various communication and latency delays within a system, and can include actions taken within about ten seconds, within about thirty seconds, within about a minute, within about five minutes, or within about ten minutes of the action occurring.

[0017] As described in more detail herein, distributed fibre optic (DFO) sensors can use the optical fibre to monitor properties along the length of a wellbore. Similarly, distributed temperature sensing systems (DTS) can be used to measure the temperature along the wellbore. The main advantage of these DFO sensors is that the measurement can be made along the entire length of the wellbore over long periods of time as the entire deployed optical fibre cable is the sensor. This can avoid the need to move the tool and aiding more economical operations. The use of DTS for leak detection however, brings a few limitations including: 1) the use of thermal profiles alone for leak identification often results in inconclusive results, and 2) it is difficult to achieve controlled shut in versus flowing conditions outside of casing to compare and determine leak locations from baseline thermal profiles.

[0018] As described in more detail herein, the system comprises a DAS/DTS interrogator that is optically coupled to the optical fibre deployed in the well. Various sensors (e.g., the distributed optical fibre acoustic sensors, etc.) can be used to obtain an acoustic sampling at various points along the wellbore. The acoustic sample can then be processed using signal processing architecture with various feature extraction techniques (e.g., spectral feature extraction techniques) to obtain a measure of one or more frequency domain features that enable selectively extracting the acoustic signals of interest from background noise and consequently aiding in improving the accuracy of the identification of the movement of fluids and/or solids (e.g., liquid ingress locations, gas influx locations, constricted fluid flow locations, etc.) through comparison with an event signature in real time. As used herein, various frequency domain features can be obtained from the acoustic signal. In some contexts the frequency domain features can also be referred to as spectral features or spectral descriptors.

[0019] In addition to the use of DAS/DTS data, additional sensor data such as pressure sensors and/or flow sensors can be used to obtain data within the wellbore. As an example, a flow sensor or pressure sensor can be used to detect fluid flow within the wellbore and/or an annulus within the wellbore. The sensors can be used with controlled shut-in and/or flow conditions to correlate in time the resulting pressure and/or flow conditions with the processed DAS data. The resulting correlation can then be used to determine a presence and location of an event as well as being used in the process of calibrating the measurements from the optical fibre to physical depths in the wellbore.

[0020] When an optical fiber is installed in a wellbore and/or when an interrogator is coupled to an optical fiber, an initial calibration procedure can be performed to align signals sensed from the optical fiber with physic depths within the wellbore. This calibration process can be useful based on various factors that can occur upon installation of the fiber. For example, when the optical fibre is run or installed in or along a tubing string down the wellbore, a greater distance of fibre optic cable can be run relative to a corresponding distance of the tubing string. For example, coiling, kinking, spooling, or other types of bends may occur in the fibre optic cable as it is run into or along the tubing string, resulting in a greater length of fibre optic cable being disposed in the wellbore than a corresponding physical length of tubing string along the longitudinal depth of the wellbore.

[0021] In a numerical example, 5,500 meter (m) of fibre optic cable can be run into or alongside a 5,000 m section of tubing string. As a result, acoustic events associated with a measured depth of the fibre optic cable may actually be associated with a physical property (e.g., a change in inner diameter leading to turbulence in fluid flow) or event (e.g., a leak, a temperature change due to a leak or inflow, etc.) that occurs at a numerically-different physical depth in the wellbore itself. If an acoustic event is detected at a measured depth of 2,750 m (half the measured depth in the fibre optic cable), assuming an even compression of the fibre optic cable throughout the tubing string, that acoustic event should be associated with a physical depth in the wellbore of 2,500 m (half the physical depth in the wellbore). The resulting difference can then create errors in locations between measured properties and the actual physical depths within the wellbore. These errors can lead to issues in identifying the physical locations for workover procedures, properly identifying completion equipment, and the like.

[0022] As used herein, the term "physical depth" refers to a depth as measured along the longitudinal axis of the wellbore, which can be a vertical wellbore, a deviated wellbore, and/or a horizontal wellbore. Thus, "depth" may not represent a purely vertical depth within the wellbore and rather represents a length along the wellbore. The term "sensed depth" corresponds to a length along the optical fibre as measured by a time-of-flight calculation from a reflected or backscattered optical signal traveling on the optical fibre. The systems disclosed herein allow for a calibration or correlation between the sensed depth and the physical depth within the wellbore so that the sensed depth can be aligned with the physical features within the wellbore.

[0023] Examples of this disclosure provide systems and methods for calibrating the DAS to more accurately correlate sensed depths along the fibre optic cable with physical depths in the wellbore. For a given wellbore, there may exist identifiable, acoustically or thermally detectable events or properties throughout the wellbore, such as changes in pipe diameter that lead to acoustically-detectable turbulence and occur at a known depth, petrophysical properties of the wellbore that occur at a known depth, and other acoustically-detectable properties, such as fluid flow through sand screens, gravel packs and the like, and/or thermally detectable (e.g., due to a temperature change, etc.) events which also occur at a known depth.

[0024] By identifying such acoustic and thermal events in the signals sensed from the optical fibre that can be associated with known physical depths in the wellbore, measured depths from the optical fibre may be correlated with physical depths in the wellbore. For example, depths may be correlated by applying one or more of a correlation factor and an offset to the measured depth in order to correlate the measured depth with a physical depth in the wellbore. In some examples, a single correlation factor does not accurately correlate the entire length of the optical fibre optic with a physical depth in the wellbore, for example, where the packing of the optical fibre optic inside or along the tubing string is not even throughout the length of the tubing string. In these situations, a piecewise or multi-segment depth correlation can be established and applied to different portions of the sensed depths from the optical fibre. In some embodiments, a non-linear correlation can be established along the length of the wellbore using a plurality of known correlation points.

[0025] In one example, an acoustic signal can be sensed or obtained from the optical fibre in the wellbore, and an origination point within the acoustic signal can be determined. The origination point may identify an upper point of the fibre optic cable and, in one example, is determined using a "tap test," in which the upper end of the fibre optic cable is tapped, or physically contacted, which generates an easily-identifiable response in the acoustic signal obtained from the fibre optic cable. This upper point may represent a location at or near the wellhead that is physical accessible and may be correlated with a physical depth of zero, for example, serving as a baseline by which to correlate or calculate a relationship between other measured depths from the acoustic signal with physical features of the wellbore at known, physical depths in the wellbore.

[0026] A bottom point within the acoustic signal can also be determined. The bottom point may identify a lower point of the optical fibre within the wellbore. In one example, the bottom point can be determined by identifying a reflection point in the acoustic signal, using for example, a termination point in the optical fibre. In some embodiments, the optical fibre can extend to a lower point and return to a point at or near the surface. In these embodiments, a given event can be detected at two points along the optical fibre corresponding to the same physical location within the wellbore. This information can be used to identify multiple correlation points (e.g., tally points as discussed herein) along the length of the optical fiber and the wellbore.

[0027] As noted above, the origination point may be correlated with physical depth information for the wellbore, such as being at or near the top of the wellbore (e.g., a depth of zero) or at some other known relation to an upper end of the wellbore (e.g., associated with the rotary Kelly bushing (RKB), a point a known distance from the wellhead, etc.). Similarly, the bottom point may be correlated with physical depth information for the wellbore, such as a known depth of a tubing string spanned by the optical fibre, or a known depth relative to a downhole tool string able to measure its own physical depth in the wellbore (e.g., as measured by a logging tool in the tool string, a depth counter on the surface, etc.). Continuing the above numerical example, the bottom point of the optical fibre may be identified at a measured depth of 5,500 m, but since it is known that the tubing string only extends 5,000 m downhole, the bottom point in the acoustic signal can be correlated with 5,000 m.

[0028] A depth calibration can determined, and subsequently applied to sensed acoustic signals, for example by correlating a sensed or measured depth from the acoustic signal with a physical depth in the wellbore. Again, continuing the above numerical example, an example depth calibration is a calibration factor of approximately 0.909, such that when applied to a sensed depth of 5,500 m, a corrected physical depth of 5,000 m is obtained. While this example provides a single depth calibration factor, the calibration factor can take a variety of forms as described in more detail herein.

[0029] In another example, multiple depth calibrations may be applied across the length of the optical fibre (e.g., a piecewise calibration, a non-linear calibration, etc.). In addition to the origination and bottom points, one or more tally points can also be identified within the acoustic signal, which correspond to identifiable acoustic events associated with known physical features of the wellbore. As used herein, a "tally point" can refer to an identifiable location based on physical features or events within the wellbore than have corresponding acoustic and/or thermal signatures than can be sensed or detected using the optical fibre, thereby allowing for calibration points in both the physical space and sensed signal space. For example, a change in pipe inner diameter can create a turbulent fluid flow and/or temperature change, which in turn has an associated, identifiable acoustic signature and temperature profile; the physical depth(s) of such inner diameter changes may be known based on records and logs of the wellbore. Thus, the pipe inner diameter change can be correlated by both a physical depth and a sensed depth. As another example, the presence of a sand screen or gravel pack can have an associated, identifiable acoustic signature when fluid flow is present; the physical depth(s) of sand screens and gravel packs can also be known from wellbore data.

[0030] In some embodiments, a piece-wise calibration can be used along the length of the wellbore between the tally points. For example, first and second acoustic events can be present within the acoustic signal at increasing physical depths within the wellbore, and a tally point can be identified for each acoustic event. A first depth calibration can be applied between, and based on, the origination point and the first tally point (e.g., a first calibration factor to relate the measured depths of those points in the acoustic signal with their known, physical depths); a second depth calibration can be applied between, and based on, the first tally point and the second tally point (e.g., a second calibration factor to relate the measured depths of those points in the acoustic signal with their known, physical depths); and a third depth calibration can be applied between, and based on, the second tally point and the bottom point (e.g., a third calibration factor to relate the measured depths of those points in the acoustic signal with their known, physical depths). Additionally, while generally described as a calibration factor to convert the measured depth to a physical depth, in other examples the depth calibration factor may additionally or alternately include a depth offset to account for a shift in the measured depth relative to the physical depth in the wellbore, thereby improving the accuracy of the correlation. These and other examples are explained in further detail below.

[0031] Referring now to Figure 1, an example of a wellbore operating environment 100 is shown. As will be described in more detail below, embodiments of completion assemblies comprising distributed acoustic sensor (DAS) system and/or a distributed temperature sensor

(DTS) system in accordance with the principles described herein can be positioned in environment 100.

[0032] As shown in Figure 1, exemplary environment 100 includes a wellbore 114 traversing a subterranean formation 102, casing 112 lining at least a portion of wellbore 114, and a tubular 120 extending through wellbore 114 and casing 112. A plurality of spaced screen elements or assemblies 118 can be provided along tubular 120. In addition, a plurality of spaced zonal isolation devices 117 and gravel packs 122 are provided between tubular 120 and the sidewall of wellbore 114. In some embodiments, the operating environment 100 includes a workover and/or drilling rig positioned at the surface and extending over the wellbore 114.

[0033] In general, the wellbore 114 can be drilled into the subterranean formation 102 using any suitable drilling technique. The wellbore 114 can extend substantially vertically from the earth's surface over a vertical wellbore portion, deviate from vertical relative to the earth's surface over a deviated wellbore portion, and/or transition to a horizontal wellbore portion. In general, all or portions of a wellbore may be vertical, deviated at any suitable angle, horizontal, and/or curved. In addition, the wellbore 114 can be a new wellbore, an existing wellbore, a straight wellbore, an extended reach wellbore, a sidetracked wellbore, a multi-lateral wellbore, and other types of wellbores for drilling and completing one or more production zones. As illustrated, the wellbore 114 includes a substantially vertical producing section 150, which is an open hole completion (e.g., casing 112 does not extend through producing section 150). Although section 150 is illustrated as a vertical and open hole portion of wellbore 114 in Figure 1, embodiments disclosed herein can be employed in sections of wellbores having any orientation, and in open or cased sections of wellbores. The casing 112 extends into the wellbore 114 from the surface and is cemented within the wellbore 114 with cement 111.

[0034] Tubular 120 can be lowered into wellbore 114 for performing an operation such as drilling, completion, workover, treatment, and/or production processes. In the embodiment shown in Figure 1, the tubular 120 is a completion assembly string including a fiber optic cable that can serve as a distributed acoustic sensor (DAS) and/or a distributed temperature sensor (DTS) (e.g., more generally a distributed fiber optic (DFO) sensor) coupled thereto. However, in general, embodiments of the tubular 120 can function as a different type of structure in a wellbore including, without limitation, as a drill string, casing, liner, jointed tubing, and/or coiled tubing. Further, the tubular 120 may operate in any portion of the wellbore 114 (e.g., vertical, deviated, horizontal, and/or curved section of wellbore 114). Embodiments of DFO (e.g., DAS, DTS, etc.) systems described herein can be coupled to the exterior of the tubular 120, or in some embodiments, disposed within an interior of the tubular 120, as shown in Figures 3A and 3B. When the DFO (e.g., DAS, DTS, etc.) fibre is coupled to the exterior of the tubular 120, the DFO (e.g., DAS, DTS, etc.) fiber can be positioned within a control line, control channel, or recess in the tubular 120. In some embodiments, a sand control system can include an outer shroud to contain the tubular 120 and protect the system during installation. A control line or channel can be formed in the shroud and the DFO (e.g., DAS, DTS, etc.) system can be placed in the control line or channel.

[0035] The tubular 120 extends from the surface to the producing zones and generally provides a conduit for fluids to travel from the formation 102 to the surface. A completion assembly including the tubular 120 can include a variety of other equipment or downhole tools to facilitate the production of the formation fluids from the production zones. For example, zonal isolation devices 117 are used to isolate the various zones within the wellbore 114. In this embodiment, each zonal isolation device 117 can be a packer (e.g., production packer, gravel pack packer, frac-pac packer, etc.). The zonal isolation devices 117 can be positioned between the screen assemblies 118, for example, to isolate different gravel pack zones or intervals along the wellbore 114 from each other. In general, the space between each pair of adjacent zonal isolation devices 117 defines a production interval.

[0036] The screen assemblies 118 provide sand control capability. In particular, the sand control screen elements 118, or other filter media associated with wellbore tubular 120, can be designed to allow fluids to flow therethrough but restrict and/or prevent particulate matter of sufficient size from flowing therethrough. In some embodiments, gravel packs 122 can be formed in the annulus 119 between the screen elements 118 (or tubular 120) and the sidewall of the wellbore 114 in an open hole completion. In general, the gravel packs 122 comprise relatively coarse granular material placed in the annulus to form a rough screen against the ingress of sand into the wellbore while also supporting the wellbore wall. The gravel pack 122 is optional and may not be present in all completions.

[0037] The fluid flowing into the tubular 120 may comprise more than one fluid component. Typical components include natural gas, oil, water, steam, and/or carbon dioxide. The relative proportions of these components can vary over time based on conditions within the formation

102 and the wellbore 114. Likewise, the composition of the fluid flowing into the tubular 120 sections throughout the length of the entire production string can vary significantly from section to section at any given time.

[0038] As fluid is produced into the wellbore 114 and into the completion assembly string, the flow of the various fluids into the wellbore 114 and/or through the wellbore 114 can create acoustic sounds and thermal signatures that can be detected using the optical fibre for acoustic sensing such as the DAS and/or DTS system. Each type of event such as the different fluid flows and fluid flow locations can produce an acoustic signature with unique frequency domain features and/or unique temperature features associated with a thermal signature. For example, a leak representing fluid flow past a restriction, through an annulus, and/or through the formation can create unique sound profiles over a frequency domain such that each event may have a unique acoustic signature based on a plurality of frequency domain features. Similarly, a leak can present a unique thermal profile such as cooling in the event of a gas leak that can be detected through DTS using the optical fibre. In addition, since the location of such restrictions, changes in pipe inner diameter, and formation profiles may be known, the identification of an associated acoustic or thermal signature enables the correlation of a measured depth from the optical fibre with a physical depth in the wellbore 114.

[0039] In Figure 1, the DFO (e.g., DAS, DTS, etc.) system comprises an optical fibre 162 based acoustic sensing system that uses the optical backscatter component of light injected into the optical fibre for detecting acoustic/vibration perturbations (e.g., dynamic strain) along the length of the fibre 162. Optical backscatter can also be used to detect thermal changes relative to a baseline, which can be used to provide DTS on the same or a different optical fibre. The light can be generated by a light generator or source 166 such as a laser, which can generate light pulses. The optical fibre 162 acts as the sensor element with no additional transducers in the optical path, and measurements can be taken along the length of the entire optical fibre 162. The measurements of the backscattered components of the light can then be detected by an optical receiver such as sensor 164 and selectively filtered to obtain measurements from a given depth point or range, thereby providing for a distributed measurement that has selective data for a plurality of zones along the optical fibre 162 at any given time. As will be explained further below, these measurements may be associated with a given depth point or range within the optical fibre 162 (e.g., a measured depth), which is then correlated with a physical depth in the wellbore 114 through the DFO (e.g., DAS, DTS, etc.) calibration procedures described herein. In this manner, the optical fibre 162 effectively functions as a distributed array of acoustic sensors spread over the entire length of the optical fibre 162, which typically spans at least the production zone 150 of the wellbore 114, to detect downhole acoustic signals/vibration perturbations. Components of the backscattered light can also be processed to determine a thermal change in the optical fibre, which can provide an indication of physical structures for use in calibrating the sensed depths to the physical depths.

[0040] The light reflected back up the optical fibre 162 as a result of the backscatter can travel back to the source, where the signal can be routed to and collected by a sensor 164 and processed (e.g., using a processor 168). In general, the time the light takes to return to the collection point is proportional to the distance traveled along the optical fibre 162. A calculation of the time-of-flight of the backscattered light can then be used to characterize the signal from portions of the optical fibre. The resulting backscattered light arising along the length of the optical fibre 162 can be used to characterize the environment around the optical fibre 162. The use of a controlled light source 166 (e.g., having a controlled spectral width and frequency) may allow the backscatter to be collected and any disturbances along the length of the optical fibre 162 to be analyzed. In general, any acoustic or dynamic strain disturbances along the length of the optical fibre 162 can result in a change in the properties of the backscattered light, allowing for a distributed measurement of both the acoustic magnitude, frequency and in some cases of the relative phase of the disturbance. Similarly, the temperature can affect the properties of the backscattered light, allowing for a distributed measurement of the temperature along the length of the optical fibre 162.

[0041] An acquisition device 160 can be coupled to one end of the optical fibre 162. As discussed herein, the light source 166 can generate the light (e.g., one or more light pulses), and the sensor 164 can collect and analyze the backscattered light returning up the optical fibre 162. In some contexts, the acquisition device 160 including the light source 166 and the sensor 164 can be referred to as an interrogator. In addition to the light source 166 and the sensor 164, the acquisition device 160 generally comprises a processor 168 in signal communication with the sensor 164 to perform various analysis and calibration steps described in more detail herein. While shown as being within the acquisition device 160, the processor can also be located outside of the acquisition device 160 including being located remotely from the acquisition device 160. The sensor 164 can be used to obtain data at various rates and may obtain data at a sufficient rate to detect the acoustic signals of interest with sufficient bandwidth. In an embodiment, depth resolution ranges of between about 1 meter and about 10 meters can be achieved.

[0042] While the system 100 described herein can be used with a DAS and/or DTS system to acquire an acoustic or thermal signal for a location or depth range in the wellbore 114, in general, any suitable acoustic signal acquisition system and/or temperature detection system can be used with the processing steps disclosed herein. For example, various microphones or other sensors can be used to provide an acoustic signal at a given location based on the acoustic signal processing described herein. This would allow for the active generation of a noise or temperature change for purposes of establishing a tally point within the wellbore.

[0043] In addition to the DAS system, a surface sensor or sensor system 152 can be used to obtain additional data for the wellbore. The surface sensor system 152 can comprise one or more sensors such as pressure sensors, flow sensors, temperature sensors, and the like. The sensors can detect the conditions within the tubular 120 and/or in one or more annuli such as annuli 119. While only a single annulus between the tubular 120 and the casing 112 is illustrated in Figure 1, multiple annuli can be present. For example, more than one casing string can often be set at or near the surface of the wellbore during drilling, which can result in two or more annuli (e.g., an annulus between the tubular 120 and the casing 112, an annulus between a first casing 112 and a second casing, an annulus between a casing string and the wellbore wall, etc.). As used herein, reference to the term “surface” can refer to a location above or at the well head (e.g., at the Kelly bushing, rig floor, etc.), near the ground level, and/or within the first 100 m, within the first 150 m, within the first 200 m, or within about the first 300 m along the wellbore as measured from ground level. The additional sensors can be used to provide data, that when correlated with the DAS and/or DTS data, can help to identify events at locations within the wellbore that can be used as tally points.

[0044] Specific spectral signatures can be determined for each event by considering one or more frequency domain features. The spectral signatures can define ranges or thresholds for each type of event. The resulting spectral signatures can then be used along with processed acoustic signal data to determine if an event is occurring at a depth range of interest. The spectral signatures can be determined by considering the different types of movement and flow occurring within a wellbore and characterizing the frequency domain features for each type of movement. In some examples, the spectral signatures are associated with an event that occurs at a known depth in the wellbore 114 (e.g., changes in pipe inner diameter causing turbulent flow, locations of flow restrictions), and thus the sensed depth of the spectral signature in the signal from the optical fibre 162 may be correlated with a physical depth in the wellbore 114 to identify a tally point.

[0045] By way of example, fluid, which can contain particulates or sand, can be considered as an example of an event generating an acoustic signal. As schematically illustrated in Figure 2 and shown in the cross-sectional illustrations in Figures 3A and 3B, a fluid, which can contain sand 202, can flow from the formation 102 into the wellbore 114 and then into the tubular 120. As the fluid flows into the tubular 120, the sand 202 can collide against the inner surface 204 of the tubular 120, and with the fibre itself in cases where the fibre is placed within the tubular, in a random fashion. The resulting random impacts can produce a random, broadband acoustic signal that can be captured on the optical fibre 162 coupled (e.g., strapped) to the tubular 120. The sand 202 entering the wellbore 114 can be carried within a carrier fluid 206, and the carrier fluid 206 can also generate high intensity acoustic background noise when entering the wellbore 114 due to the turbulence associated with the fluid flowing into the tubular 120. The presence of sand and/or fluid inflow can then be correlated with a production location within the wellbore (e.g., a producing sleeve, a producing zone within the formation, etc.) to identify a tally point for use in the calibration process.

[0046] A number of acoustic signal sources, which may be associated with known depths in the wellbore 114, can also be considered along with the types of acoustic signals these sources generate. In general, a variety of signal sources can be considered, at least some of which occur at a known depth in the wellbore 114, including fluid flow with or without sand through the formation 102, fluid flow with or without sand 202 through a gravel pack 122, fluid flow with or without sand within or through the tubular 120 and/or sand screen 118, fluid flow with sand 202 within or through the tubular 120 and/or sand screen 118, fluid flow without sand 202 into the tubular 120 and/or sand screen 118, gas / liquid inflow, fluid leaks past restrictions (e.g., gas leaks, liquid leaks, etc.), mechanical instrumentation, and geophysical acoustic noises and potential point reflection noise within the fibre caused by cracks in the fibre optic cable / conduit under investigation. Each of these events can be correlated to a physical feature in the wellbore to be used as a tally point.

[0047] Addition features such as inflow locations, changes in flow conditions at know petrophysical features (e.g., shale layers, impermeable layers, etc.) can also be used as a basis for correlating physical feature comprising petrophysical properties or locations in the subterranean formation with acoustic and thermal events to serve as tally points. Tally points can also comprise features present on the fibre optic cable itself. These can include splice locations, end points, stress locations, and the like. Any of the tally points can be used to develop the depth correlations as described herein.

[0048] When optical fibres are used within the wellbore, several configurations are possible. In some embodiments, the fibre optic cable can be deployed on a workover tool into the wellbore. In these embodiments, the fiber optic cable can be deployed with a tool string and with a known arrangement with respect to the tool string. For example, the end of the optical fibre can be attached to a location on the tool string, and the tool string can be deployed into the wellbore with a measured physical depth. For example, the tool string can contain logging tools to identify a location within the wellbore and/or a surface depth measurement device can be used to track the depth of the tool string within the wellbore. The resulting relationship between the optical fibre and known depth of the tool string can then be used to correlate the depth of the optical fibre in the wellbore. Tally points can then be determined based on the known physical depths and sensed depth locations (e.g., an end point depth, etc.).

[0049] In some embodiments, the optical fibre can be installed in a wellbore. In these embodiments, the optical fibre can be deployed into the wellbore and terminate at a lower point within the wellbore (e.g., a single pass configuration), or the optical fibre can extend to a lower point and pass back towards the surface of the wellbore, thereby forming a "U" shaped installation within the wellbore (e.g., a multi-pass configuration). Each of these configurations is described in more detail herein.

[0050] The single pass configuration in which the optical fibre extends into and terminates at a lower point in the wellbore is shown in Figure 4A. As shown schematically in Figure 4A, a tubular 120 can be lowered into the wellbore 114. The tubular 120 may be for performing an operation such as drilling, completion, workover, treatment, and/or production processes. As explained above, the sensing system can comprise an optical fibre 162 that uses the optical backscatter component of light injected into the optical fibre 162 for detecting acoustic and or thermal signals along the length of the optical fibre 162. In the example of Figure 4A, the optical fibre 162 can be disposed within the interior of the tubular 120; however, in other examples the optical fibre 162 can be coupled to the exterior of the tubular 120 (e.g., an exterior of a production tubing, casing, etc.), as explained above. A reflection point 450 can exists at the lower end of the optical fibre 162 disposed within the tubular 120.

[0051] The wellbore 114 can include identifiable, acoustically-detectable events or properties, such as turbulent flow events or temperature changes that can lead to acoustically-detectable turbulence and/or thermal signatures that occur at a known physical depth that can correlated to petrophysical properties of the wellbore acoustically-detectable properties, such as fluid flow through sand screens 118, gravel packs 122, and the like. In Figures 4A and 4B, a first such acoustic event 454 can occur at a first known physical depth, while a second such acoustic event 456 can occurs at a second known physical depth.

[0052] Due to coiling, kinking, or other types of bends that occur in the optical fibre 162 as it is run into or along the tubular 120, a greater length of optical fibre 162 can exist between the upper end of the tubular 120 (e.g., the surface) and the lower end of the tubular 120 (e.g., the reflection point 450) than a corresponding physical length of the tubular 120 between those same points. As a result, although the acoustic events 454, 456 occur at known physical depths, the sensed depths from the optical fibre 162 may be different (e.g., deeper) than the physical depths of the events 454, 456.

[0053] Since the events 454, 456 occur at known physical depths, identifying corresponding acoustic and/or thermal events in the signal from the optical fibre 162 (e.g., at a measured depth) allows the sensed depths from the optical fibre 162 to be correlated with physical depths of the events 454, 456 in the wellbore 114 to identify tally points. For example, depths may be correlated by applying one or more of a correlation factor and an offset to the measured depth of an acoustic event from the optical fibre 162 in order to correlate the measured depth with the physical depth of an event 454, 456 in the wellbore 114.

[0054] A multi-pass configuration is illustrated in Figure 4B. As shown in Figure 4B, another embodiment can have a tubular 120 lowered into the wellbore 114. The tubular 120 is similar to that described above with respect to Figure 4A. Like Figure 4A, an optical fibre 162 is used for detecting acoustic and/or thermal signals along the length of the optical fibre 162. In the example of Figure 4B, the optical fibre 162 can be disposed within the interior of the tubular 120; however, in other examples the optical fibre 162 is coupled to the exterior of the tubular 120 and/or casing. Unlike the example of Figure 4A, in Figure 4B the optical fibre 162 includes a first section 162a that passes from a top end of the tubular 120 (e.g., an origination point) to a bottom end of the tubular 120 (e.g., a bottom point) and a second section 162b that passes from the bottom point back to the origination point in a multi-pass configuration. A turnaround sub 452 facilitates a redirection of the optical fibre 162 at the bottom end of the tubular 120. The turnaround sub 452 may comprise a U-shaped tube that allows the optical fibre 162 to turn around at the bottom end of the tubular 120 and run back up to the top end of the tubular 120, to a reflection point 450 also at the top end of the tubular 120 as shown. The acoustic events 454, 456 described above also apply in the example of Figure 4B.

[0055] As described above, due to coiling, kinking, or other types of bends that occur in the optical fibre 162 as it is run into or along the tubular 120, through the turnaround sub 452, and back to the top end of the tubular 120, a greater length of optical fibre 162 can exist between the upper end of the tubular 120 (e.g., the surface), the turnaround sub 452 at the lower end of the tubular 120, and back to the reflection point 450 at the upper end of the tubular 120 than a corresponding physical length of the tubular 120 between those same points. As a result, although the acoustic events 454, 456 occur at known physical depths, the sensed depths from the optical fibre 162 may be different (e.g., deeper) than the physical depths of the events 454, 456. In some embodiments, measurement errors can result in the sensed depth detecting a shallower depth than the physical depth.

[0056] Since the events 454, 456 occur at known physical depths, identifying corresponding acoustic events in the signal from the optical fibre 162 (e.g., at a sensed depth) allows the sensed depths from the optical fibre 162 to be correlated with physical depths of the events 454, 456 in the wellbore 114. For example, depths may be correlated by applying one or more of a correlation factor and an offset to the sensed depth of an acoustic event from the optical fibre 162 in order to correlate the sensed depth with the physical depth of an event 454, 456 in the wellbore 114.

[0057] In one example, an acoustic or thermal signal can be obtained from the optical fibre 162 in the wellbore 114, and an origination point within the acoustic or thermal signal can be determined. The origination point may identify an upper point of the optical fibre 162 and, in one example, is determined using a “tap test,” in which the upper end of the optical fibre 162 is tapped, or physically contacted, which generates an easily-identifiable response in the acoustic signal obtained from the optical fibre 162. This upper point may be correlated with a physical depth of zero, for example, serving as a baseline by which to correlate or calculate a relationship between other measured depths from the acoustic signal with physical features of the wellbore 114 at known, physical depths in the wellbore (e.g., events 454, 456).

[0058] A bottom point within the acoustic signal can also be determined. The bottom point may identify a lower point of the optical fibre 162 within the wellbore 114. In the example of Figure 4A, the bottom point can correspond to the reflection point 450 and is thus determined by identifying a corresponding reflection point in the sensed signal. For example, since the acoustic events 454, 456 will impact the signal on both the downward and the upward directions of travel in the optical fibre 162, creating an approximate reflection point that separates mirror images of the acoustic response generated by the events 454, 456. In the example of Figure 4B, the bottom point corresponds to the turnaround sub 452 and is thus determined by identifying a reflection point in the acoustic signal other than the physical reflection point 450 in Figure 4B. For example, since the acoustic events 454, 456 impact the signal in the outgoing direction (e.g., downward to the turnaround sub 452 and upward to the reflection point 450) as well as the incoming direction (e.g., downward from the reflection point 450 to the turnaround sub 452 and upward to the beginning of the optical fibre 162), the bottom point may be determined by identifying one of the acoustic events 454, 456 in the first section of the optical fibre 162a, identifying the same of the acoustic events 454, 456 in the second section of the optical fibre 162b, and establishing the bottom point as the mid-point between the acoustic events 454, 456 in the first section 162a and the second section 162b.

[0059] As explained above, the origination point may be correlated with physical depth information for the wellbore 114, such as being at the top of the wellbore 114 (e.g., a depth of zero) or at some other known relation to an upper end of the wellbore (e.g., associated with the rotary kelly bushing (RKB)). Similarly, the bottom point may be correlated with physical depth information for the wellbore 114, such as a known depth of the tubular 120 spanned by the optical fibre, a known depth of the turnaround sub 452 in relation to the tubular 120, or a known depth relative to a downhole tool string able to measure its own physical depth in the wellbore 114 (e.g., where the tool string extends a known distance beyond the end of the optical fibre 162). In addition, one or more tally points can be determined by correlating sensed depths with known physical depths of features within the wellbore, formation, or the optical fiber.

Continuing the numerical example given above, the bottom point of the optical fibre 162 may be identified at a measured depth of 5,500 m, but since it is known that the tubular 120 only extends 5,000 m downhole (or the turnaround sub 452 is positioned 5,000 m downhole), the bottom point in the acoustic signal is correlated with 5,000 m.

[0060] A depth calibration can be determined, and subsequently applied to sensed acoustic signals from the optical fibre 162, for example by correlating a sensed or measured depth from the acoustic signal with a physical depth in the wellbore 114. Again, continuing the above numerical example, an example depth calibration is a calibration factor of approximately 0.909, such that when applied to a sensed depth of 5,500 m, a corrected physical depth of 5,000 m is obtained. The use of a single calibration factor can take the form of an equation such as equation 1:

$$y = a(x) \qquad \text{Eq. 1}$$

where y and x can be the physical depth and the sensed depth, and a can represent the calibration factor. In some embodiments, y can be the physical depth and x can represent the sensed depth from the optical fibre. By knowing a correlation at any one point (e.g., a lower end point), the value of the calibration factor “a” can be determined.

[0061] When a plurality of correlated points are known, a better fit to the known data may be provided by an equation such as equation 2:

$$y = a(x) + b \qquad \text{Eq. 2.}$$

where y and x are still the physical depth and the sensed depth, a is a calibration factor, and b is an offset. Using two correlated points provides for two equations with two variables, which allows the values of “a” and “b” to be determined.

[0062] While equations 1 and 2 represent linear equations, higher order equations can be used when more tally points are known. For example, a non-linear equation such as equation 3 can be used when 4 or more correlated points are known:

$$y = d(x^3) + e(x^2) + a(x) + b \qquad \text{Eq. 3}$$

where y and x are the physical depth and the sensed depth, d, e, and a are calibration factors, and b is the offset. When four points are known, there are four equations with four variables that allows for the values of “a”, “b”, “c”, and “d” to be determined. When more than 4 known points are available, a best fit to the equation can be obtained and used as the calibration. While shown as a third order equation, and type or order of non-linear equations can be used for the calibration and used with the known correlation values.

[0063] In some embodiments, a single correlation factor may not sufficiently correlate the entire length of the optical fibre 162 with a physical depth in the wellbore 114 within a desired accuracy, for example, where the packing of the optical fibre 162 inside or along the tubular 120 is not even throughout the length of the tubular 120. In this instance, multiple depth calibrations may be applied across the length of the optical fibre 162. In addition to the origination and bottom points, one or more tally points can also be identified within the acoustic signal, which correspond to one or more of the identifiable acoustic events 454, 456 associated with known physical features of the wellbore 114. For example, the event 454 could correspond to a change in pipe inner diameter creates a turbulent fluid flow, while the event 456 could correspond to the presence of a sand screen, both of which have associated, identifiable acoustic signatures when fluid flow is present, and both of which occur at known physical depths.

[0064] Continuing this example, the events 454, 456 can be present within the acoustic signal and/or thermal signal from the optical fibre 162 at increasing physical depths within the wellbore, and a tally point can be identified for each event 454, 456. A first depth calibration can be applied between, and based on, the origination point and the first tally point (e.g., a first calibration factor to relate the sensed depths of those points in the acoustic signal with their known, physical depths), for example, using equations 1 or 2. A second depth calibration can be applied between, and based on, the first tally point and the second tally point (e.g., a second calibration factor to relate the sensed depths of those points in the acoustic signal with their known, physical depths)), for example, using equations 1 or 2. Finally, a third depth calibration can be applied between, and based on, the second tally point and the bottom point (e.g., a third calibration factor to relate the sensed depths of those points in the acoustic signal with their known, physical depths)), for example, using equations 1 or 2. In each of the first, second, and third depth calibrations, the determined values for the calibration factor(s) and/or offset can be different since each one will be based on the correlated points. This allows for a more accurate overall calibration as each section can more accurately represent the calibration between the known points. In the example of Figure 4B, the depth calibrations may be separately identified further for each of the first section 162a and the second section 162b. Additionally, while generally described as a calibration factor to convert the sensed depth to a physical depth, in other examples the depth calibration factor may additionally or alternately include a depth offset to account for a shift in the measured depth relative to the physical depth in the wellbore. Particularly in the example of Figure 4B, a depth offset may be applied to address a shift created by the presence of the turnaround sub 452.

[0065] While described in terms of a first, second, and third depth calibration, any suitable number of calibrations for a plurality of calibration sections can be determined along the optical fibre. The number of depth calibration sections may depend on the number and type of tally points available within the sensed signals. As more sensed signals are available, the greater the number of depth calibration sections that can be used. Further, a non-linear calibration can be used across the entire wellbore or any portion thereof. For example, some sections between tally points and/or end points can use linear calibration equations, and other sections can use a non-linear calibration equation. This allows the calibration to be adjusted within a desired accuracy.

[0066] As shown schematically in Figure 5, an embodiment of a system for detecting various identifiable acoustic event conditions that can be correlated with physical features of the wellbore 114, which have a known depth in the wellbore 114, can comprise a data extraction unit 402, a processing unit 404, a peripheral sensor data correlation unit 408, and/or an output or visualization unit 406. The system comprises an interrogator 160 connected to the optical fibre 162 deployed in the wellbore. The data from the interrogator 160 is transmitted in real time to a data processing unit 402 that receives and processes the data in real time. The data processing unit 402 can perform a variety of processing steps on the acoustic sample data. In an embodiment, the acoustic sample can be noise de-trended. The noise de-trended acoustic variant data can be subjected to an optional spatial filtering step following the pre-processing steps, if present. This is an optional step and helps focus primarily on an interval of interest in the wellbore. For example, the spatial filtering step can be used to focus on a producing interval where there is maximum likelihood of a leak when a leak event is being examined. In an embodiment, the spatial filtering can narrow the focus of the analysis to a reservoir section and also allow a reduction in data typically of the order of ten times, thereby simplifying the data analysis operations. The resulting data set produced through the conversion of the raw optical data can be referred to as the acoustic sample data.

[0067] The processing unit 402 can also be used to generate and extract acoustic descriptors and/or temperature features (e.g., also referred to as frequency domain features herein) from the acquired data set (e.g., an acoustic data set, a thermal data set, etc.). In an embodiment, the data extraction unit 402 can obtain the optical data and perform the initial pre-processing steps to obtain the initial acoustic information from the signal returned from the wellbore. Various analyses can be performed including frequency domain feature extraction, frequency band extraction, frequency analysis and/or transformation, intensity and/or energy calculations, and/or determination of one or more frequency domain features of the acoustic data. In order to obtain the frequency domain features, the data processing unit 402 can be further configured to perform Discrete Fourier transformations (DFT) or a short time Fourier transform (STFT) of the acoustic variant time domain data measured at each depth section along the fibre or a section thereof to spectrally check the conformance of the acoustic sample data to one or more acoustic signatures. The spectral conformance check can be used to determine if the expected signature of an event, in particular an event that can be associated with a known depth in the wellbore 114, is present in the acoustic sample data. Spectral feature extraction through time and space can be used to determine the spectral conformance and determine if an acoustic signature (e.g., a sand ingress fingerprint, gas influx, hydraulic fracturing signature, etc.) is present in the acoustic sample. Within this process, various frequency domain features can be calculated for the acoustic sample data. The resulting spectral conformance check can then be used to determine the locations of the tally points. For example, it can be the event detection that is used as the basis to determine and correlate the sensed depth with a known physical feature in the wellbore, thereby allowing the tally points to be determined.

[0068] The use of the frequency domain features to identify one or more events has a number of advantages. First, the use of the frequency domain features results in significant data reduction relative to the raw DAS data stream. Thus, a number of frequency domain features can be calculated to allow for event identification while the remaining data (which may include data that does not correspond to an identifiable acoustic event that can be associated with a known depth in the wellbore 114) can be discarded or otherwise stored, while the remaining analysis can performed using the frequency domain features. Even when the raw DAS data is stored, the remaining processing power is significantly reduced through the use of the frequency domain features rather than the raw acoustic data itself. Further, the use of the frequency domain features provides a concise, quantitative measure of the spectral character or acoustic signature of specific sounds pertinent to downhole fluid surveillance, calibrating the measured depths from the optical fibre 162 of the DAS, and other applications that may directly be used for real-time, application-specific signal processing.

[0069] While a number of frequency domain features can be determined for the acoustic sample data, not every frequency domain feature may be used in the characterization of each acoustic signature. The frequency domain features represent specific properties or characteristics of the acoustic signals. There are a number of factors that can affect the frequency domain feature selection for each event. For example, a chosen descriptor should remain relatively unaffected by the interfering influences from the environment such as interfering noise from the electronics/optics, concurrent acoustic sounds, distortions in the transmission channel, and the like. Such frequency domain features can include, but are not limited to, the spectral centroid, the spectral spread, the spectral roll-off, the spectral skewness, the root mean square (RMS) band energy (or the normalized sub-band energies / band energy ratios), a loudness or total RMS energy, spectral flatness, spectral scope, spectral kurtosis, a spectral flux, spectral entropy, and a spectral autocorrelation function.

[0070] Similar to frequency domain features, a number of temperature features can be obtained from the temperature measurements obtained from the optical fibre and the interrogator. The temperature features can provide an indication of one or more temperature trends at a given location in the wellbore during a measurement period. The resulting features can form a distribution of temperature results that can then be used with various signatures or models to identify one or more events within the wellbore at the location.

[0071] The temperature measurements can represent output values from the DTS system, which can be used with or without various types of pre-processing such as noise reduction, smoothing, and the like, as described in more detail herein. When background temperature measurements are used, the background measurement can represent a temperature measurement at a location within the wellbore taken in the absence of the flow of a fluid. For example, a temperature profile along the wellbore can be taken when the well is initially formed and/or the wellbore can be shut in and allowed to equilibrate to some degree before measuring the temperatures at various points in the wellbore. The resulting background temperature measurements or temperature profile can then be used in determining the temperature features in some embodiments.

[0072] In general, the temperature features represent statistical variations of the temperature measurements through time and/or depth. For example, the temperature features can represent statistical measurements or functions of the temperature within the wellbore that can be used with various models to determine whether or not fluid flow events have occurred. The temperature features can be determined using various functions and transformations, and in some embodiments can represent a distribution of results. In some embodiments, the temperature features can represent a normal or Gaussian distribution. In some embodiments, the temperature measurements can represent measurement through time and depth, such as variations taken first with respect to time and then with respect to depth or first with respect to depth and then with respect to time. The resulting distributions can then be used with models such as multivariate models to determine the presence of the fluid flow events.

[0073] In some embodiments, the temperature features can include various features including, but not limited to, a depth derivative of temperature with respect to depth, a temperature excursion measurement, a baseline temperature excursion, a peak-to-peak value, a Fast Fourier transform (FFT), a Laplace transform, a wavelet transform, a derivative of temperature with respect to depth, a heat loss parameter, an autocorrelation, and combinations thereof.

[0074] In some embodiments, the temperature features can comprise a depth derivative of temperature with respect to depth. This feature can be determined by taking the temperature measurements along the wellbore and smoothing the measurements. Smoothing can comprise a variety of steps including filtering the results, de-noising the results, or the like. In some embodiments, the temperature measurements can be median filtered within a given window to smooth the measurements. Once smoothed, the change in the temperature with depth can be determined. In some embodiments, this can include taking a derivative of the temperature measurements with respect to depth along the longitudinal axis of the wellbore 114. The depth derivative of temperature values can then be processed, and the measurement with a zero value (e.g., representing a point of no change in temperature with depth) that have preceding and proceeding values that are non-zero and have opposite signs in depth (e.g., zero below which the value is negative and above positive or vice versa) can have the values assign to the nearest value. This can then result in a set of measurements representing the depth derivative of temperature with respect to depth.

[0075] In some embodiments, the temperature features can comprise a temperature excursion measurement. The temperature excursion measurement can comprise a difference between a temperature reading at a first depth and a smoothed temperature reading over a depth range, where the first depth is within the depth range. In some embodiments, the temperature excursion measurement can represent a difference between de-trended temperature measurements over an interval and the actual temperature measurements within the interval. For example, a depth range can be selected within the wellbore 114. The temperature readings within a time window can be obtained within the depth range and de-trended or smoothed. In some embodiments, the de-trending or smoothing can include any of those processes described above, such as using median filtering of the data within a window within the depth range. For median filtering, the larger the window of values used, the greater the smoothing effect can be on the measurements. For the temperature excursion measurement, a range of windows from about 10 to about 100 values, or between about 20-60 values (e.g., measurements of temperature within the depth range) can be used to median filter the temperature measurements. A difference can then be taken between the temperature measurement at a location and the de-trended (e.g., median filtered) temperature values. The temperature measurements at a location can be within the depth range and the values being used for the median filtering. This temperature feature then represents a temperature excursion at a location along the wellbore 114 from a smoothed temperature measurement over a larger range of depths around the location in the wellbore 114.

[0076] In some embodiments, the temperature features can comprise a baseline temperature excursion. The baseline temperature excursion represents a difference between a de-trended baseline temperature profile and the current temperature at a given depth. In some embodiments, the baseline temperature excursion can rely on a baseline temperature profile that can contain or define the baseline temperatures along the length of the wellbore 114. As described herein, the baseline temperatures represent the temperature as measured when the wellbore 114 is shut in. This can represent a temperature profile of the formation in the absence of fluid flow. While the wellbore 114 may affect the baseline temperature readings, the baseline temperature profile can approximate a formation temperature profile. The baseline temperature profile can be determined when the wellbore 114 is shut in and/or during formation of the wellbore 114, and the resulting baseline temperature profile can be used over time. If the condition of the wellbore 114 changes over time, the wellbore 114 can be shut in and a new baseline temperature profile can be measured or determined. It is not expected that the baseline temperature profile is re-determined at specific intervals, and rather it would be determined at discrete times in the life of the wellbore 114. In some embodiments, the baseline temperature profile can be re-determined and used to determine one or more temperature features such as the baseline temperature excursion.

[0077] Once the baseline temperature profile is obtained, the baseline temperature measurements at a location in the wellbore 114 can be subtracted from the temperature measurement detected by the temperature monitoring system 110 at that location to provide baseline subtracted values. The results can then be obtained and smoothed or de-trended. For example, the resulting baseline subtracted values can be median filtered within a window to smooth the data. In some embodiments, a window between 10 and 500 temperature values, between 50 and 400 temperature values, or between 100 and 300 temperature values can be used to median filter the resulting baseline subtracted values. The resulting smoothed baseline subtracted values can then be processed to determine a change in the smoothed baseline subtracted values with depth. In some embodiments, this can include taking a derivative of the smoothed baseline subtracted values with respect to depth along the longitudinal axis of the wellbore. The resulting values can represent the baseline temperature excursion feature.

[0078] In some embodiments, the temperature features can comprise a peak-to-peak temperature value. This feature can represent the difference between the maximum and minimum values (e.g., the range, etc.) within the temperature profile along the wellbore 114. In some embodiments, the peak-to-peak temperature values can be determined by detecting the maximum temperature readings (e.g., the peaks) and the minimum temperature values (e.g., the dips) within the temperature profile along the wellbore 114. The difference can then be determined within the temperature profile to determine peak-to-peak values along the length of the wellbore 114. The resulting peak-to-peak values can then be processed to determine a change in the peak-to-peak values with respect to depth. In some embodiments, this can include taking a derivative of the peak-to-peak values with respect to depth along the longitudinal axis of the wellbore 114. The resulting values can represent the peak-to-peak temperature values.

[0079] Other temperature features can also be determined from the temperature measurements. In some embodiments, various statistical measurements can be obtained from the temperature measurements along the wellbore 114 to determine one or more temperature features. For example, a cross-correlation of the temperature measurements with respect to time can be used to determine a cross-correlated temperature feature. The temperature measurements can be smoothed as described herein prior to determining the cross-correlation with respect to time. As another example, an autocorrelation measurement of the temperature measurements can be obtained with respect to depth. Autocorrelation is defined as the cross-correlation of a signal with itself. An autocorrelation temperature feature can thus measure the similarity of the signal with itself as a function of the displacement. An autocorrelation temperature feature can be used, in applications, as a means of anomaly detection for one or more events (e.g., fluid flow, fluid leaks, sand ingress, etc.). The temperature measurements can be smoothed and/or the resulting autocorrelation measurements can be smoothed as described herein to determine the autocorrelation temperature features.

[0080] In some embodiments, the temperature features can comprise a Fast Fourier transform (FFT) of the distributed temperature sensing (e.g., DTS) signal. This algorithm can transform the distributed temperature sensing signal from the time domain into the frequency domain, thus allowing detection of the deviation in DTS along length (e.g., depth). This temperature feature can be utilized, for example, for anomaly detection for one or more events.

[0081] In some embodiments, the temperature features can comprise the Laplace transform of DTS. This algorithm can transform the DTS signal from the time domain into Laplace domain allows us to detect the deviation in the DTS along length (e.g., depth of wellbore 114). This temperature feature can be utilized, for example, for anomaly detection for event detection. This feature can be utilized, for example, in addition to (e.g., in combination with) the FFT temperature feature.

[0082] In some embodiments, the temperature features can comprise a wavelet transform of the distributed temperature sensing (e.g., DTS) signal and/or of the derivative of DTS with respect to depth, dT/dz. The wavelet transform can be used to represent the abrupt changes in the signal data. This feature can be utilized, for example, in fluid flow detection. A wavelet is described as an oscillation that has zero mean, which can thus make the derivative of DTS in depth more suitable for this application. In embodiments and without limitation, the wavelet can comprise a Morse wavelet, an Analytical wavelet, a Bump wavelet, or a combination thereof.

[0083] In some embodiments, the temperature features can comprise a derivative of DTS with respect to depth, or dT/dz. The relationship between the derivative of flowing temperature T_f with respect to depth (L) (e.g., dT_f/dL) has been described by several models. For example, and without limitation, the model described by Sagar (Sagar, R., Doty, D. R., & Schmidt, Z. (1991, November 1). Predicting Temperature Profiles in a Flowing Well. Society of Petroleum Engineers. doi:10.2118/19702-PA) which accounts for radial heat loss due to conduction and describes a relationship (Equation (5) below) between temperature change in depth and mass rate. The mass rate wt is conversely proportional to the relaxation parameter A and, as the relaxation parameter A increases, the change in temperature in depth increases. Hence this temperature feature can be designed to be used, for example, in events comprising flow quantification.

$$\frac{dT_f}{dL} = -A\left[(T_f - T_e) + \frac{g}{g_c}\frac{\sin\theta}{JC_{pm}A} - \frac{F_c}{A}\right]. \tag{5}$$

The formula for the relaxation parameter, A, is provided in Equation (6):

$$A = \left(\frac{2\pi}{w_t C_{pl}}\right)\left(\frac{r_{ti} U k_e}{k_e + r_{ti} U f/12}\right)\left(\frac{1}{86{,}400 \times 12}\right) \tag{6}$$

A = coefficient, ft^{-1}
C_{pL} = specific heat of liquid, Btu/lbm-°F
C_{pm} = specific heat of mixture, Btu/lbm-°F
C_{po} = specific heat of oil, Btu/lbm-°F
C_{pw} = specific heat of water, Btu/lbm-°F
d_c = casing diameter, in.
d_t = tubing diameter, in.
d_{wb} = wellbore diameter, in.
D = depth, ft
D_{inj} = injection depth, ft
f = modified dimensionless heat conduction time function for long times for earth
$f(t)$ = dimensionless transient heat conduction time function for earth
F_c = correction factor

$\overline{F}_c$ = average correction factor for one length interval
g = acceleration of gravity, 32.2 ft/sec^2
g_c = conversion factor, 32.2 ft-lbm/sec^2-lbf
g_G = geothermal gradient, °F/ft
h = specific enthalpy, Btu/lbm
J = mechanical equivalent of heat, 778 ft-lbf/Btu
k_{an} = thermal conductivity of material in annulus, Btu/D-ft-°F
k_{ang} = thermal conductivity of gas in annulus, Btu/D-ft-°F
k_{anw} = thermal conductivity of water in annulus, Btu/D-ft-°F
k_{cem} = thermal conductivity of cement, Btu/D-ft-°F
k_e = thermal conductivity of earth, Btu/D-ft-°F
L = length of well from perforations, ft
L_{in} = length from perforation to inlet, ft
p = pressure, psi
p_{wh} = wellhead pressure, psig
q_{gf} = formation gas flow rate, scf/D
q_{ginj} = injection gas flow rate, scf/D
q_o = oil flow rate, STB/D
q_w = water flow rate, STB/D
Q = heat transfer between fluid and surrounding area, Btu/lbm
r_{ci} = inside casing radius, in.
r_{co} = outside casing radius, in.
r_{ti} = inside tubing radius, in.
r_{to} = outside tubing radius, in.
r_{wb} = wellbore radius, in.
R_{gL} = gas/liquid ratio, scf/STB
T = temperature, °F
T_{bh} = bottomhole temperature, °F
T_c = casing temperature, °F
T_e = surrounding earth temperature, °F
T_{ein} = earth temperature at inlet, °F
T_f = flowing fluid temperature, °F
T_{fin} = flowing fluid temperature at inlet, °F
T_h = cement/earth interface temperature, °F
U = overall heat transfer coefficient, Btu/D-ft^2-°F
v = fluid velocity, ft/sec
V = volume
w_t = total mass flow rate, lbm/sec
Z = height from bottom of hole, ft
Z_{in} = height from bottom of hole at inlet, ft
α = thermal diffusivity of earth, 0.04 ft^2/hr
γ_{API} = oil gravity, °API
γ_g = gas specific gravity (air=1)
γ_o = oil specific gravity
γ_w = water specific gravity
θ = angle of inclination, degrees
μ = Joule-Thomson coefficient

[0084] In some embodiments, the temperature features can comprise a heat loss parameter. As described hereinabove, Sagar's model describes the relationship between various input parameters, including the mass rate w_t and temperature change in depth dT_f/d_L. These parameters can be utilized as temperature features in a machine learning model which uses features from known cases (production logging results) as learning data sets, when available. These features can include geothermal temperature, deviation, dimensions of the tubulars 120 that are in the well (casing 112, tubing 120, gravel pack 122 components, etc.), as well as the wellbore 114, well head pressure, individual separator rates, downhole pressure, gas/liquid ratio, and/or a combination thereof. Such heat loss parameters can, for example, be utilized as inputs in a machine learning model for events comprising fluid flow quantification of the mass flow rate w_t.

[0085] In some embodiments, the temperature features an comprise a time-depth derivative and/or a depth-time derivative. A temperature feature comprising a time-depth derivative can comprise a change in a temperature measurement at one or more locations across the wellbore taken first with respect to time, and a change in the resulting values with respect to depth can then be determined. Similarly, a temperature feature comprising a depth-time derivative can comprise a change in a temperature measurement at one or more locations across the wellbore taken first with respect to depth, and a change in the resulting values with respect to time can then be determined.

[0086] In some embodiments, the temperature features can be based on dynamic temperature measurements rather than steady state or flowing temperature measurements. In order to obtain dynamic temperature measurements, a change in the operation of the system (e.g., wellbore) can be introduced, and the temperature monitored using the temperature monitoring system. For example in a wellbore environment, the change in conditions can be introduced by shutting in the wellbore, opening one or more sections of the wellbore to flow, introducing a fluid to the wellbore (e.g., injecting a fluid), and the like. When the wellbore is shut in from a flowing state, the temperature profile along the wellbore may be expected to change from the flowing profile to the baseline profile over time. Similarly, when a wellbore that is shut in is opened for flow, the temperature profile may change from a baseline profile to a flowing profile. Based on the change in the condition of the wellbore, the temperature measurements can change dynamically over time. In some embodiments, this approach can allow for a contrast in thermal conductivity to be determined between a location or interval having radial flow (e.g., into or out of the wellbore) to a location or interval without radial flow. One or more temperature features can then be determined using the dynamic temperature measurements. Once the temperature features are determined from the temperature measurements obtained from the temperature monitoring system, one or more of the temperature features can be used to identify events along the length being monitored (e.g., within the wellbore), as described in more detail herein.Any of these frequency domain features, temperature features, or any combination of these frequency domain features and/or temperature features, can be used to provide an acoustic signature for a downhole event, which in at least some examples may be used to calibrate the DAS by correlating the measured depth from the optical fibre 162 signal with a known depth in the wellbore 114 of such downhole event. In an embodiment, a selected set of characteristics can be used to provide the acoustic signature for each event, and/or all of the frequency domain features that are calculated can be used as a group in characterizing the acoustic signature for an event. The specific values for the frequency domain features that are calculated can vary depending on the specific attributes of the acoustic signal acquisition system, such that the absolute value of each frequency domain feature can change between systems. In some embodiments, the frequency domain features can be calculated for each event based on the system being used to capture the acoustic signal and/or the differences between systems can be taken into account in determining the frequency domain feature values for each signature between the systems used to determine the values and the systems used to capture the acoustic signal being evaluated.

[0087] In order to obtain the frequency domain features, the acoustic sample data can be converted to the frequency domain. In an embodiment, the raw optical data may contain or represent acoustic data in the time domain. A frequency domain representation of the data can be obtained using a Fourier Transform. Various algorithms can be used as known in the art. In some embodiments, a Short Time Fourier Transform technique or a Discrete Time Fourier transform can be used. The resulting data sample may then be represented by a range of frequencies relative to their power levels at which they are present. The raw optical data can be transformed into the frequency domain prior to or after the application of the spatial filter. In general, the acoustic sample will be in the frequency domain in order to determine the spectral centroid and the spectral spread. In an embodiment, the processor 168 can be configured to perform the conversion of the raw acoustic data and/or the acoustic sample data from the time domain into the frequency domain. In the process of converting the signal to the frequency domain, the power across all frequencies within the acoustic sample can be analyzed. The use of the processor 168 to perform the transformation may provide the frequency domain data in real time or near real time.

[0088] The data processing unit 402 can then be used to analyze the acoustic sample data in the frequency domain to obtain one or more of the frequency domain features and provide an output with the determined frequency domain features for further processing. In some embodiments, the output of the frequency domain features can include features that are not used to determine the presence of every event.

[0089] The output of the processor with the frequency domain features for the acoustic sample data can then be used to calibrate the DAS, as well as determine the presence of one or more events at one or more locations in the wellbore corresponding to depth intervals over which the acoustic data is acquired or filtered. In some embodiments, the determination of the presence of one or more events can include comparing the frequency domain features with the frequency domain feature thresholds or ranges in each event signature. When the frequency domain features in the acoustic sample data match one or more of the event signatures, the event can be identified as having occurred during the sample data measurement period, which can be in real time. Various outputs can be generated to display or indicate the presence of the one or more events.

[0090] The data transmitted from the interrogator (that includes the frequency domain feature data) can then be further processed using a sequence of data processing steps as shown in the processing sequence 404 in Figure 5. The processing sequence 404 can comprise a series of steps including an anomaly detection step, a signature extraction step, an event classification step, a calibration step, and an output step. The processing sequence 404 may also include an application step, in which case the determined calibration is applied to future-collected and processed data from the optical fibre 162. The descriptor data are first processed using an event-detection) algorithm to determine the presence of any acoustic and/or thermal response(s) that may be associated with a known, physical depth in the wellbore 114. While there are several ways to implement the event detection algorithm, amplitude thresholding of the data relative to surface noise captured by the DAS on the fibre optic cable dispersed at or near the surface (e.g., within the first 100 meters) of the well head can be used. As an example of amplitude thresholding, an acoustic intensity over the entire bandwidth can be averaged over the surface or near surface measurements (e.g., in the first 300 m of acoustic data) acquisitions to provide an estimate of the average surface acoustic noise. A threshold can then be taken as a percentage of this average. For example, the amplitude threshold can be between about 90% and about 95% of the average. The presence of the signal within the wellbore can be detected when the amplitude of the acoustic event captured exceeds the threshold value. The frequency and amplitude characteristics of the surface noise may also be used to suppress and/or reduce the background noise within the selected window to identify presence of signals at the surface, if needed. This enables a zero point depth recognition, helps to reduce or eliminate surface noise contributions, helps to reduce or eliminate the DAS interrogator noise contributions, allows for the capture of acoustic events and renders the captured events in a format ready for signature recognition, and uses processed data (as compared to raw DAS data) as the primary feed to the processing sequence. While amplitude thresholding is used, other time based digital processing approaches could also be used.

[0091] Once the data is initially processed, the events can be recognized (e.g., as events having amplitudes over the thresholds), and the corresponding data from the portion of the acoustic sample can be extracted as a depth-time event block. Figure 6A illustrates an example of a depth-time event block show depth versus amplitude. Once the depth-time blocks are amplitude thresholded, the corresponding data may appear as shown in Figure 6B, with the surface noise filtered out and the events highlighted.

[0092] In the second step 412 of the processing sequence 404, the event blocks can be further analyzed by extracting the frequency domain features and/or temperature features at the event depths and times identified by the event detection step and comparing the extracted frequency domain features and/or temperature features to the event signatures to match the frequency domain features for each identified event with an appropriate signature (e.g., a signature that indicates that the event can be associated with a known, physical depth in the wellbore 114). The extraction of the frequency domain features and/or temperature features can be performed prior to the data being sent to the processing sequence such that the extraction of the frequency domain features and/or temperature features involves filtering the received frequency domain features and/or temperature features for the depth and times identified by the event detection, or the extraction of the frequency domain features and/or temperature features can be performed only after the depth-time blocks have been identified.

[0093] In either event, the resulting frequency domain features and/or temperature features can be compared with one or more event signatures to identify if an event associated with a known, physical depth in the wellbore 114 has occurred in the event classification step 414. In some embodiments, the event signatures can include frequency domain signatures and/or temperature features for fluid flow past a change in inner diameter of a pipe, fluid flow past a sand screen or gravel pack, a liquid leak, a gas leak, a self-induced hydraulic fracture, a shear re-activation, or another such event (e.g., an unrecognized event category or other non-leak signatures, which can be used for comparison).

[0094] In some embodiments, the resulting frequency domain features and/or temperature features can be used in one or more models (e.g., machine learning models, etc.) to identify if an event associated with a known, physical depth in the wellbore 114 has occurred in the event classification step 414. The one or more first or wellbore event models can comprise one or more models configured to accept one or more of the frequency domain features and/or temperature features as input(s) and provide an indication of whether or not there is an event at the particular location along the length. The output of the one or more first or wellbore event models can be in the form of a binary yes/no result, and/or a likelihood of an event (e.g., a percentage likelihood, etc.). Other outputs providing an indication of an event are also possible. In some embodiments, the one or more first or wellbore event models can comprise a a machine learning model using supervised or unsupervised learning algorithms such as a multivariate model, neural network, or the like.

[0095] In some embodiments, the one or more first or wellbore event models can comprise a multivariate model. A multivariate model allows for the use of a plurality of variables in a model to determine or predict an outcome. A multivariate model can be developed using known data on events along with features for those events to develop a relationship between the features and the presence of the event at the locations within the available data. One or more multivariate models can be developed using data, where each multivariate model uses a plurality of features as inputs to determine the likelihood of an event occurring at the particular location along the length.

[0096] The event classification step 414 can be executed at each depth location along the fibre 162 and may depend on the acoustic signatures captured at the locations identified to have an event. Once classified into the appropriate category, the intensities of the events can be determined using the normalized RMS values within the appropriate frequency bands extracted on site (e.g., which can already be one of the descriptors obtained in the extracted frequency domain features) from the raw acoustic data. The descriptor data can then be transformed and re-written as an event matrix. The same process can be carried out using temperature features to identify events as described herein. These steps can be executed in near real time at the data integration server, and the transformed decision ready well integrity event data can be stored along with some or all of the acoustic descriptor data. The classified event data may also be visualized as a three dimensional depth versus time versus event type intensity plot as shown in Figure 7A and Figure 7B to illustrate well integrity events as a function of depth and time.

[0097] Once the events are classified, the events can be used for a variety of purposes, including during calibration, such as calibration step 416. For example, events that are correlated to physical structures to form tally points in the wellbore, as described herein, can be identified. Once the calibration has been performed, step 416 can be used for event identification with the depth calibration applied to the sensed depths to identify and monitor events within the wellbore. With regard to the identified events, the output from the event identification system can be output at step 418. For example, a visual output can be generated and/or one or more control or data outputs can be generated from the identification of the event.

[0098] The event matrix may be further filtered to highlight and visualize certain types of well integrity events as shown in Figure 7C. These may also be aligned in depth to the well completion schematic and / or the geological maps (e.g., discrete pressure zones) to ascertain the source of the leaking fluid in case of liquid leaks. The use of the processing sequence 404 can result in a suitable calibration of the DAS system, in particular to correlate measured depths from the optical fibre 162 with known, physical depths in the wellbore 114.

[0099] Any of the systems and methods disclosed herein can be carried out on a computer or other device comprising a processor, such as the acquisition device 160 of Figure 1. Figure 8 illustrates a computer system 780 suitable for implementing one or more embodiments disclosed herein such as the acquisition device or any portion thereof. The computer system 780 includes a processor 782 (which may be referred to as a central processor unit or CPU) that is in communication with memory devices including secondary storage 784, read only memory (ROM) 786, random access memory (RAM) 788, input/output (I/O) devices 790, and network connectivity devices 792. The processor 782 may be implemented as one or more CPU chips.

[00100] It is understood that by programming and/or loading executable instructions onto the computer system 780, at least one of the CPU 782, the RAM 788, and the ROM 786 are changed, transforming the computer system 780 in part into a particular machine or apparatus having the novel functionality taught by the present disclosure. It is fundamental to the electrical engineering and software engineering arts that functionality that can be implemented by loading executable software into a computer can be converted to a hardware implementation by well-known design rules. Decisions between implementing a concept in software versus hardware typically hinge on considerations of stability of the design and numbers of units to be produced rather than any issues involved in translating from the software domain to the hardware domain. Generally, a design that is still subject to frequent change may be preferred to be implemented in software, because re-spinning a hardware implementation is more expensive than re-spinning a software design. Generally, a design that is stable that will be produced in large volume may be preferred to be implemented in hardware, for example in an application specific integrated circuit (ASIC), because for large production runs the hardware implementation may be less expensive than the software implementation. Often a design may be developed and tested in a software form and later transformed, by well-known design rules, to an equivalent hardware implementation in an application specific integrated circuit that hardwires the instructions of the software. In the same manner as a machine controlled by a new ASIC is a particular machine or apparatus, likewise a computer that has been programmed and/or loaded with executable instructions may be viewed as a particular machine or apparatus.

[00101] Additionally, after the system 780 is turned on or booted, the CPU 782 may execute a computer program or application. For example, the CPU 782 may execute software or firmware stored in the ROM 786 or stored in the RAM 788. In some cases, on boot and/or when the application is initiated, the CPU 782 may copy the application or portions of the application from the secondary storage 784 to the RAM 788 or to memory space within the CPU 782 itself, and the CPU 782 may then execute instructions that the application is comprised of. In some cases, the CPU 782 may copy the application or portions of the application from memory accessed via the network connectivity devices 792 or via the I/O devices 790 to the RAM 788 or to memory space within the CPU 782, and the CPU 782 may then execute instructions that the application is comprised of. During execution, an application may load instructions into the CPU 782, for example load some of the instructions of the application into a cache of the CPU 782. In some contexts, an application that is executed may be said to configure the CPU 782 to do something, e.g., to configure the CPU 782 to perform the function or functions promoted by the subject application. When the CPU 782 is configured in this way by the application, the CPU 782 becomes a specific purpose computer or a specific purpose machine.

[00102] The secondary storage 784 is typically comprised of one or more disk drives or tape drives and is used for non-volatile storage of data and as an over-flow data storage device if RAM 788 is not large enough to hold all working data. Secondary storage 784 may be used to store programs which are loaded into RAM 788 when such programs are selected for execution. The ROM 786 is used to store instructions and perhaps data which are read during program execution. ROM 786 is a non-volatile memory device which typically has a small memory capacity relative to the larger memory capacity of secondary storage 784. The RAM 788 is used to store volatile data and perhaps to store instructions. Access to both ROM 786 and RAM 788 is typically faster than to secondary storage 784. The secondary storage 784, the RAM 788, and/or the ROM 786 may be referred to in some contexts as computer readable storage media and/or non-transitory computer readable media.

[00103] I/O devices 790 may include printers, video monitors, liquid crystal displays (LCDs), touch screen displays, keyboards, keypads, switches, dials, mice, track balls, voice recognizers, card readers, paper tape readers, or other well-known input devices.

[00104] The network connectivity devices 792 may take the form of modems, modem banks, Ethernet cards, universal serial bus (USB) interface cards, serial interfaces, token ring cards, fibre distributed data interface (FDDI) cards, wireless local area network (WLAN) cards, radio transceiver cards that promote radio communications using protocols such as code division multiple access (CDMA), global system for mobile communications (GSM), long-term evolution (LTE), worldwide interoperability for microwave access (WiMAX), near field communications (NFC), radio frequency identity (RFID), and/or other air interface protocol radio transceiver cards, and other well-known network devices. These network connectivity devices 792 may enable the processor 782 to communicate with the Internet or one or more intranets. With such a network connection, it is contemplated that the processor 782 might receive information from the network, or might output information to the network (e.g., to an event database) in the course of performing the above-described method steps. Such information, which is often represented as a sequence of instructions to be executed using processor 782, may be received from and outputted to the network, for example, in the form of a computer data signal embodied in a carrier wave.

[00105] Such information, which may include data or instructions to be executed using processor 782 for example, may be received from and outputted to the network, for example, in the form of a computer data baseband signal or signal embodied in a carrier wave. The baseband signal or signal embedded in the carrier wave, or other types of signals currently used or hereafter developed, may be generated according to several methods well-known to one skilled in the art. The baseband signal and/or signal embedded in the carrier wave may be referred to in some contexts as a transitory signal.

[00106] The processor 782 executes instructions, codes, computer programs, scripts which it accesses from hard disk, floppy disk, optical disk (these various disk based systems may all be considered secondary storage 784), flash drive, ROM 786, RAM 788, or the network connectivity devices 792. While only one processor 782 is shown, multiple processors may be present. Thus, while instructions may be discussed as executed by a processor, the instructions may be executed simultaneously, serially, or otherwise executed by one or multiple processors. Instructions, codes, computer programs, scripts, and/or data that may be accessed from the secondary storage 784, for example, hard drives, floppy disks, optical disks, and/or other device, the ROM 786, and/or the RAM 788 may be referred to in some contexts as non-transitory instructions and/or non-transitory information.

[00107] In an embodiment, the computer system 780 may comprise two or more computers in communication with each other that collaborate to perform a task. For example, but not by way of limitation, an application may be partitioned in such a way as to permit concurrent and/or parallel processing of the instructions of the application. Alternatively, the data processed by the application may be partitioned in such a way as to permit concurrent and/or parallel processing of different portions of a data set by the two or more computers. In an embodiment, virtualization software may be employed by the computer system 780 to provide the functionality of a number of servers that is not directly bound to the number of computers in the computer system 780. For example, virtualization software may provide twenty virtual servers on four physical computers. In an embodiment, the functionality disclosed above may be provided by executing the application and/or applications in a cloud computing environment. Cloud computing may comprise providing computing services via a network connection using dynamically scalable computing resources. Cloud computing may be supported, at least in part, by virtualization software. A cloud computing environment may be established by an enterprise and/or may be hired on an as-needed basis from a third party provider. Some cloud computing environments may comprise cloud computing resources owned and operated by the enterprise as well as cloud computing resources hired and/or leased from a third party provider.

[00108] In an embodiment, some or all of the functionality disclosed above may be provided as a computer program product. The computer program product may comprise one or more computer readable storage medium having computer usable program code embodied therein to implement the functionality disclosed above. The computer program product may comprise data structures, executable instructions, and other computer usable program code. The computer program product may be embodied in removable computer storage media and/or non-removable computer storage media. The removable computer readable storage medium may comprise, without limitation, a paper tape, a magnetic tape, magnetic disk, an optical disk, a solid state memory chip, for example analog magnetic tape, compact disk read only memory (CD-ROM) disks, floppy disks, jump drives, digital cards, multimedia cards, and others. The computer program product may be suitable for loading, by the computer system 780, at least portions of the contents of the computer program product to the secondary storage 784, to the ROM 786, to the RAM 788, and/or to other non-volatile memory and volatile memory of the computer system 780. The processor 782 may process the executable instructions and/or data structures in part by directly accessing the computer program product, for example by reading from a CD-ROM disk inserted into a disk drive peripheral of the computer system 780. Alternatively, the processor 782 may process the executable instructions and/or data structures by remotely accessing the computer program product, for example by downloading the executable instructions and/or data structures from a remote server through the network connectivity devices 792. The computer program product may comprise instructions that promote the loading and/or copying of data, data structures, files, and/or executable instructions to the secondary storage 784, to the ROM 786, to the RAM 788, and/or to other non-volatile memory and volatile memory of the computer system 780.

[00109] In some contexts, the secondary storage 784, the ROM 786, and the RAM 788 may be referred to as a non-transitory computer readable medium or a computer readable storage media. A dynamic RAM embodiment of the RAM 788, likewise, may be referred to as a non-transitory computer readable medium in that while the dynamic RAM receives electrical power and is operated in accordance with its design, for example during a period of time during which the computer system 780 is turned on and operational, the dynamic RAM stores information that is written to it. Similarly, the processor 782 may comprise an internal RAM, an internal ROM, a cache memory, and/or other internal non-transitory storage blocks, sections, or components that may be referred to in some contexts as non-transitory computer readable media or computer readable storage media. While various embodiments in accordance with the principles disclosed herein have been shown and described above, modifications thereof may be made by one skilled in the art without departing from the spirit and the teachings of the disclosure. The embodiments described herein are representative only and are not intended to be limiting. Many variations, combinations, and modifications are possible and are within the scope of the disclosure. Alternative embodiments that result from combining, integrating, and/or omitting features of the embodiment(s) are also within the scope of the disclosure. Accordingly, the scope of protection is not limited by the description set out above, but is defined by the claims which follow, that scope including all equivalents of the subject matter of the claims. Each and every claim is incorporated as further disclosure into the specification and the claims are embodiment(s) of the present invention(s). Furthermore, any advantages and features described above may relate to specific embodiments, but shall not limit the application of such issued claims to processes and structures accomplishing any or all of the above advantages or having any or all of the above features.

[00110] Having described certain systems and methods herein, some aspects can include, but are not limited to:

[00111] In a first aspect, a method of calibrating a distributed acoustic sensor (DAS) system comprises: obtaining a backscattered optical signal from a fiber optic cable disposed within a wellbore, wherein the backscattered optical signal is representative of at least one of: an acoustic signal along the length of the fiber optic cable, or a thermal signal along the length of the fiber; determining an origination point within the backscattered optical signal, wherein the origination point identifies a first location at an upper point of the fiber optic cable within the backscattered optical signal; determining one or more features from the backscattered optical signal; identifying an event within the wellbore using the one or more features; identifying at least one tally point within physical depth information for the wellbore, wherein the at least one tally point is associated with the identified event; correlating the origination point and the at least one tally point with the physical depth information for the wellbore; and determining at least a depth calibration for the backscattered optical signal using the correlating, wherein the depth calibration correlates a sensed depth within the backscattered optical signal with a physical depth within the wellbore.

[00112] A second aspect can include, the method of the first aspect, further comprising: determining a bottom point within the backscattered optical signal, wherein the bottom point identifies a second location at a lower point of the fiber optic cable within the wellbore, wherein the correlating comprises correlating the origination point, the bottom point, and the at least one tally point with the physical depth information for the wellbore.

[00113] A third aspect can include the method of the second aspect, wherein determining the bottom point within the backscattered optical signal comprises: determining a reflection point within the fiber optic cable, wherein the reflection point is the bottom point.

[00114] A fourth aspect can include the method of any one of the first to third aspects, where the at least one tally point represent identifiable acoustic or thermal events within the backscattered optical signal; and wherein the method further comprises: correlating the at least one tally point with corresponding physical features of the wellbore; and adjusting the depth calibration based on the correlating of the at least one tally point with the corresponding physical features.

[00115] A fifth aspect can include the method of any one of the second to fourth aspects, wherein the fiber optic cable is disposed on a work string, and wherein the method further comprises: receiving the physical depth information based on a measured depth of the work string within the wellbore.

[00116] A sixth aspect can include the method of the fifth aspect, further comprising: receiving petrophysical information for the wellbore associated with a measured depth of the tool string (120), wherein correlating the origination point and the bottom point with the physical depth information comprises using the petrophysical information.

[00117] A seventh aspect can include the method of the fifth or sixth aspect, wherein determining the bottom point within the backscattered optical signal comprises: identifying the bottom point using the physical depth information of the tool string within the wellbore.

[00118] An eighth aspect can include the method of any one of the first to seventh aspects, wherein the depth calibration comprises at least one calibration factor, wherein the at least one calibration factor converts the sensed depth from the backscattered optical signal to a physical depth within the wellbore.

[00119] A ninth aspect can include the method of the eighth aspect, wherein the depth calibration further comprises a depth offset, wherein the depth offset accounts for a shift in the sensed depth relative to the physical depth within the wellbore.

[00120] A tenth aspect can include the method of any one of the first to fourth aspects, wherein the fiber optic cable is disposed in a first section and second section within the wellbore, wherein the first section passes between the origination point and the bottom point, wherein the second section passes between the bottom point and the origination point, and wherein the acoustic signal is representative of the first section and the second section.

[00121] An eleventh aspect can include the method of the tenth aspect, further comprising: identifying one or more acoustic events in the backscattered optical signal from the first section; and identifying the one or more acoustic events in the backscattered optical signal from the second section, wherein determining the bottom point comprises: identifying a reflection point between the one or more acoustic events in the first section and the one or more acoustic events in the second section as the bottom point.

[00122] A twelfth aspect can include the method of the eleventh aspect, wherein determining at least the depth calibration comprises determining a first depth calibration for the first section and determining a second depth calibration for the second section.

[00123] A thirteenth aspect can include the method of any one of the tenth to twelfth aspects, further comprising: identifying one or more tally points within the backscattered optical signal for the first section and the second section of the fiber optic cable; correlating the one or more tally points with corresponding physical features in the wellbore; and adjusting the depth calibration based on the correlating of the one or more tally points with the corresponding physical features.

[00124] A fourteenth aspect can include the method of any one of the first to thirteenth aspects, wherein the depth calibration comprises a plurality of calibration sections across a plurality of portions of the measured depth within the backscattered optical signal, wherein each calibration section of the plurality of calibration sections comprises calibration factors for the respective portion of the measured depth of the plurality of portions of the measured depth.

[00125] A fifteenth aspect can include the method of any one of the first to fourteenth aspects, wherein the one or more features comprise one or more frequency domain features.

[00126] A sixteenth aspect can include the method of the fifteenth aspect, wherein the one or more frequency domain features comprise one or more of: a spectral centroid, a spectral spread, a spectral roll-off, a spectral skewness, a root mean square (RMS) band energy, a loudness or total RMS energy, a spectral flatness, a spectral scope, a spectral kurtosis, a spectral flux, a spectral entropy, a spectral autocorrelation function, a normalized variant thereof, or any combination thereof.

[00127] A seventeenth aspect can include the method of any one of the first to sixteenth aspects, wherein the one or more feature comprises one or more temperature features.

[00128] An eighteenth aspect can include the method of the seventeenth aspect, wherein the one or more temperature features comprise one or more of: a depth derivative of temperature with respect to depth, a temperature excursion measurement, a baseline temperature excursion, a peak-to-peak value, a Fast Fourier transform (FFT), a Laplace transform, a wavelet transform, a derivative of temperature with respect to depth, a heat loss parameter, an autocorrelation, and combinations thereof.

[00129] In a nineteenth aspect, a system for providing a depth calibration for an acoustic monitoring system comprises: a processor; and a memory, wherein the memory comprises a depth calibration application that, when executed on the processor, configures the processor to: receive a backscattered optical signal indicative of an acoustic signal, a temperature signal, or both from the distributed monitoring system disposed within a wellbore, wherein the acoustic signal, the temperature signal, or both are representative of an acoustic signal along the length of the wellbore, and wherein the acoustic monitoring system comprises a fiber optic cable disposed along a length of the wellbore; determine an origination point within the acoustic signal, the temperature signal, or both, wherein the origination point identifies a first location at an upper point of the distributed monitoring system within the acoustic signal, the temperature signal, or

both; correlate the origination point and the at least one tally point with the physical depth information for the wellbore; and determine a depth calibration for the acoustic signal, the temperature signal, or both using the correlating, wherein the depth calibration correlates a sensed depth within the acoustic signal with a physical depth within the wellbore.

[00130] A twentieth aspect can include the system of the nineteenth aspect, wherein the processor is further configured to: determine a bottom point within the acoustic signal, wherein the bottom point identifies a second location at a lower point of the distributed monitoring system within the wellbore, wherein the correlating comprises correlating the origination point, the bottom point, and the at least one tally point with the physical depth information for the wellbore.

[00131] A twenty first aspect can include the system of the twentieth aspect, wherein the processor is further configured to: determine a reflection point within the fiber optic cable; and identify the reflection point as the bottom point.

[00132] A twenty second aspect can include the system of any one of the nineteenth to twenty first aspects, where the tally points represent identifiable acoustic events within the acoustic signal.

[00133] A twenty third aspect can include the system of any one of the twentieth to twenty second aspects, wherein the fiber optic cable is disposed on a work string, and wherein the processor is further configured to: receive the physical depth information based on a measured depth of the work string within the wellbore.

[00134] A twenty third aspect can include the system of the twenty third aspect, wherein the processor is further configured to: receive petrophysical information for the wellbore associated with a measured depth of the tool string, wherein the origination point and the bottom point are correlated with the physical depth information using the petrophysical information.

[00135] A twenty fifth aspect can include the system of the twenty third or twenty fourth aspect, wherein the processor is further configured to: identify the bottom point using the physical depth information of the tool string within the wellbore.

[00136] A twenty sixth aspect can include the system of any one of the nineteenth to twenty fifth aspects, wherein the depth calibration comprises at least one calibration factor, wherein the at least one calibration factor converts the sensed depth from the acoustic signal to a physical depth within the wellbore.

[00137] A twenty seventh aspect can include the system of the twenty sixth aspect, wherein the depth calibration further comprises a depth offset, wherein the depth offset accounts for a shift in the sensed depth relative to the physical depth within the wellbore.

[00138] A twenty eighth aspect can include the system of any one of the nineteenth to twenty second aspects, wherein the fiber optic cable is disposed in a first section and second section within the wellbore, wherein the first section passes between the origination point and the bottom point, wherein the second section passes between the bottom point and the origination point, and wherein the acoustic signal is representative of the first section and the second section.

[00139] A twenty ninth aspect can include the system of the twenty eighth aspect, wherein the processor is further configured to: identify one or more acoustic events in the acoustic signal from the first section; identify the one or more acoustic events in the acoustic signal from the second section; and identify a reflection point between the one or more acoustic event in the first section and the one or more acoustic events in the second section as the bottom point.

[00140] A thirtieth aspect can include the system of the twenty ninth aspect, wherein the determination of the depth calibration comprises a determination of a first depth calibration for the first section and a determination of a second depth calibration for the second section.

[00141] A thirty first aspect can include the system of any one of the twenty eighth to thirtieth aspects, wherein the processor is further configured to: identify the one or more tally points within the acoustic signal for the first section and the second section of the fiber optic cable; correlate the one or more tally points with corresponding physical features in the wellbore; and adjust the depth calibration based on the correlating of the one or more tally points with the corresponding physical features.

[00142] A thirty second aspect can include the system of any one of the nineteenth to thirty first aspects, wherein the depth calibration comprises a plurality of calibration sections across a plurality of portions of the measured depth within the acoustic signal, wherein each calibration section of the plurality of calibration sections comprises calibration factors for the respective portion of the measured depth of the plurality of portions of the measured depth.

[00143] A thirty third aspect can include the system of any one of the nineteenth to thirty second aspects, wherein the one or more features comprise one or more frequency domain features.

[00144] A thirty fourth aspect can include the system of thirty third aspect, wherein the one or more frequency domain features comprise one or more of: a spectral centroid, a spectral spread, a spectral roll-off, a spectral skewness, a root mean square (RMS) band energy, a loudness or total RMS energy, a spectral flatness, a spectral scope, a spectral kurtosis, a spectral flux, a spectral entropy, a spectral autocorrelation function, a normalized variant thereof, or any combination thereof.

[00145] A thirty fifth aspect can include the system of any one of the nineteenth to thirty fourth aspects, wherein the one or more feature comprise one or more temperature features.

[00146] A thirty sixth aspect can include the system of the thirty fifth aspect, wherein the one or more temperature features comprise one or more of: a depth derivative of temperature with respect to depth, a temperature excursion measurement, a baseline temperature excursion, a peak-to-peak value, a Fast Fourier transform (FFT), a Laplace transform, a wavelet transform, a derivative of temperature with respect to depth, a heat loss parameter, an autocorrelation, and combinations thereof.

[00147] Additionally, the section headings used herein are provided for consistency with the suggestions under 37 C.F.R. 1.77 or to otherwise provide organizational cues. These headings shall not limit or characterize the invention(s) set out in any claims that may issue from this disclosure. Specifically and by way of example, although the headings might refer to a "Field," the claims should not be limited by the language chosen under this heading to describe the so-called field. Further, a description of a technology in the "Background" is not to be construed as an admission that certain technology is prior art to any invention(s) in this disclosure. Neither is the "Summary" to be considered as a limiting characterization of the invention(s) set forth in issued claims. Furthermore, any reference in this disclosure to "invention" in the singular should not be used to argue that there is only a single point of novelty in this disclosure. Multiple inventions may be set forth according to the limitations of the multiple claims issuing from this disclosure, and such claims accordingly define the invention(s), and their equivalents, that are protected thereby. In all instances, the scope of the claims shall be considered on their own merits in light of this disclosure, but should not be constrained by the headings set forth herein.

[00148] Use of broader terms such as comprises, includes, and having should be understood to provide support for narrower terms such as consisting of, consisting essentially of, and comprised substantially of. Use of the term "optionally," "may," "might," "possibly," and the like with respect to any element of an embodiment means that the element is not required, or alternatively, the element is required, both alternatives being within the scope of the embodiment(s). Also, references to examples are merely provided for illustrative purposes, and are not intended to be exclusive.

[00149] While preferred embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the disclosure. For example, the relative dimensions of various parts, the materials from which the various parts are made, and other parameters can be varied. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

[00150] Also, techniques, systems, subsystems, and methods described and illustrated in the various embodiments as discrete or separate may be combined or integrated with other systems, modules, techniques, or methods without departing from the scope of the present disclosure. Other items shown or discussed as directly coupled or communicating with each other may be indirectly coupled or communicating through some interface, device, or intermediate component, whether electrically, mechanically, or otherwise. Other examples of changes, substitutions, and alterations are ascertainable by one skilled in the art and could be made without departing from the spirit and scope disclosed herein.

CLAIMS

We claim:

1. A method of calibrating a distributed acoustic sensor (DAS) system, the method comprising:

obtaining a backscattered optical signal from a fiber optic cable (162) disposed within a wellbore (114), wherein the backscattered optical signal is representative of at least one of: an acoustic signal along the length of the fiber optic cable, or a thermal signal along the length of the fiber;

determining an origination point within the backscattered optical signal, wherein the origination point identifies a first location at an upper point of the fiber optic cable (162) within the backscattered optical signal;

determining one or more features from the backscattered optical signal;

identifying an event (454, 456) within the wellbore using the one or more features;

identifying at least one tally point within physical depth information for the wellbore (114), wherein the at least one tally point is associated with the identified event (454, 456);

correlating the origination point and the at least one tally point with the physical depth information for the wellbore (114); and

determining at least a depth calibration for the backscattered optical signal using the correlating, wherein the depth calibration correlates a sensed depth within the backscattered optical signal with a physical depth within the wellbore (114).

2. The method of claim 1, further comprising:

determining a bottom point within the backscattered optical signal, wherein the bottom point identifies a second location at a lower point of the fiber optic cable within the wellbore (114);

wherein the correlating comprises correlating the origination point, the bottom point, and the at least one tally point with the physical depth information for the wellbore (114).

3. The method of claim 2, wherein determining the bottom point within the backscattered optical signal comprises:

determining a reflection point within the fiber optic cable (162), wherein the reflection point is the bottom point.

4. The method of any one of claims 1-3,

where the at least one tally point represent identifiable acoustic or thermal events (454, 456) within the backscattered optical signal; and

wherein the method further comprises:

correlating the at least one tally point with corresponding physical features of the wellbore (114); and

adjusting the depth calibration based on the correlating of the at least one tally point with the corresponding physical features.

5. The method of any one of claims 2-4, wherein the fiber optic cable (162) is disposed on a work string, and wherein the method further comprises:

receiving the physical depth information based on a measured depth of the work string (120) within the wellbore (114).

6. The method of claim 5, further comprising:

receiving petrophysical information for the wellbore associated with a measured depth of the tool string (120), wherein correlating the origination point and the bottom point with the physical depth information comprises using the petrophysical information.

7. The method of claim 5 or 6, wherein determining the bottom point within the backscattered optical signal comprises:

identifying the bottom point using the physical depth information of the tool string (120) within the wellbore (114).

8. The method of any one of claims 1-7, wherein the depth calibration comprises at least one calibration factor, wherein the at least one calibration factor converts the sensed depth from the backscattered optical signal to a physical depth within the wellbore (114).

9. The method of claim 8, wherein the depth calibration further comprises a depth offset, wherein the depth offset accounts for a shift in the sensed depth relative to the physical depth within the wellbore (114).

10. The method of any one of claims 1-4, wherein the fiber optic cable (162) is disposed in a first section (162a) and second section (162b) within the wellbore (114), wherein the first section (162a) passes between the origination point and the bottom point, wherein the second section (162b) passes between the bottom point and the origination point, and wherein the acoustic signal is representative of the first section and the second section.

11. The method of claim 10, further comprising:

identifying one or more acoustic events (454, 456) in the backscattered optical signal from the first section (162a); and

identifying the one or more acoustic events (454, 456) in the backscattered optical signal from the second section (162b),

wherein determining the bottom point comprises:

identifying a reflection point between the one or more acoustic events (454, 456) in the first section (162a) and the one or more acoustic events (454, 456) in the second section (162b) as the bottom point.

12. The method of claim 11, wherein determining at least the depth calibration comprises determining a first depth calibration for the first section (162a) and determining a second depth calibration for the second section (162b).

13. The method of any one of claims 10-12, further comprising:

identifying one or more tally points within the backscattered optical signal for the first section (162a) and the second section (162b) of the fiber optic cable (162);

correlating the one or more tally points with corresponding physical features in the wellbore (114); and

adjusting the depth calibration based on the correlating of the one or more tally points with the corresponding physical features.

14. The method of any one of claims 1-13, wherein the depth calibration comprises a plurality of calibration sections across a plurality of portions of the measured depth within the backscattered optical signal, wherein each calibration section of the plurality of calibration sections comprises calibration factors for the respective portion of the measured depth of the plurality of portions of the measured depth.

15. The method of any one of clams 1-14, wherein the one or more features comprise one or more frequency domain features.

16. The method of claim 15, wherein the one or more frequency domain features comprise one or more of: a spectral centroid, a spectral spread, a spectral roll-off, a spectral skewness, a root mean square (RMS) band energy, a loudness or total RMS energy, a spectral flatness, a spectral scope, a spectral kurtosis, a spectral flux, a spectral entropy, a spectral autocorrelation function, a normalized variant thereof, or any combination thereof.

17. The method of any one of claims 1-16, wherein the one or more feature comprises one or more temperature features.

18. The method of claim 17, wherein the one or more temperature features comprise one or more of: a depth derivative of temperature with respect to depth, a temperature excursion measurement, a baseline temperature excursion, a peak-to-peak value, a Fast Fourier transform (FFT), a Laplace transform, a wavelet transform, a derivative of temperature with respect to depth, a heat loss parameter, an autocorrelation, and combinations thereof.

19. A system for providing a depth calibration for an acoustic monitoring system, the system comprising:

a processor; and

a memory, wherein the memory comprises a depth calibration application that, when executed on the processor, configures the processor to:

receive a backscattered optical signal indicative of an acoustic signal, a temperature signal, or both from the distributed monitoring system disposed within a wellbore, wherein the acoustic signal, the temperature signal, or both are representative of an acoustic signal along the length of the wellbore, and wherein the acoustic monitoring system comprises a fiber optic cable disposed along a length of the wellbore;

determine an origination point within the acoustic signal, the temperature signal, or both, wherein the origination point identifies a first location at an upper point of the distributed monitoring system within the acoustic signal, the temperature signal, or both;

correlate the origination point and the at least one tally point with the physical depth information for the wellbore (114); and

determine a depth calibration for the acoustic signal, the temperature signal, or both using the correlating, wherein the depth calibration correlates a sensed depth within the acoustic signal with a physical depth within the wellbore.

20. The system of claim 19, wherein the processor is further configured to:

determine a bottom point within the acoustic signal, wherein the bottom point identifies a second location at a lower point of the distributed monitoring system within the wellbore,

wherein the correlating comprises correlating the origination point, the bottom point, and the at least one tally point with the physical depth information for the wellbore (114).

21. The system of claim 20, wherein the processor is further configured to:

determine a reflection point within the fiber optic cable; and

identify the reflection point as the bottom point.

22. The system of any one of claims 19-21, where the tally points represent identifiable acoustic events within the acoustic signal.

23. The system of any one of claims 20-22, wherein the fiber optic cable is disposed on a work string, and wherein the processor is further configured to:

receive the physical depth information based on a measured depth of the work string within the wellbore.

24. The system of claim 23, wherein the processor is further configured to:

receive petrophysical information for the wellbore associated with a measured depth of the tool string, wherein the origination point and the bottom point are correlated with the physical depth information using the petrophysical information.

25. The system of claim 23 or 24, wherein the processor is further configured to:

identify the bottom point using the physical depth information of the tool string within the wellbore.

26. The system of any one of claims 19-25, wherein the depth calibration comprises at least one calibration factor, wherein the at least one calibration factor converts the sensed depth from the acoustic signal to a physical depth within the wellbore.

27. The system of claim 26, wherein the depth calibration further comprises a depth offset, wherein the depth offset accounts for a shift in the sensed depth relative to the physical depth within the wellbore.

28. The system of any one of claims 19-22, wherein the fiber optic cable is disposed in a first section and second section within the wellbore, wherein the first section passes between the origination point and the bottom point, wherein the second section passes between the bottom point and the origination point, and wherein the acoustic signal is representative of the first section and the second section.

29. The system of claim 28, wherein the processor is further configured to:

identify one or more acoustic events in the acoustic signal from the first section;

identify the one or more acoustic events in the acoustic signal from the second section; and

identify a reflection point between the one or more acoustic event in the first section and the one or more acoustic events in the second section as the bottom point.

30. The system of claim 29, wherein the determination of the depth calibration comprises a determination of a first depth calibration for the first section and a determination of a second depth calibration for the second section.

31. The system of any one of claims 28-30, wherein the processor is further configured to:

identify the one or more tally points within the acoustic signal for the first section and the second section of the fiber optic cable;

correlate the one or more tally points with corresponding physical features in the wellbore; and

adjust the depth calibration based on the correlating of the one or more tally points with the corresponding physical features.

32. The system of any one of claims 19-31, wherein the depth calibration comprises a plurality of calibration sections across a plurality of portions of the measured depth within the acoustic signal, wherein each calibration section of the plurality of calibration sections comprises calibration factors for the respective portion of the measured depth of the plurality of portions of the measured depth.

33. The method of any one of clams 19-32, wherein the one or more features comprise one or more frequency domain features.

34. The method of claim 33, wherein the one or more frequency domain features comprise one or more of: a spectral centroid, a spectral spread, a spectral roll-off, a spectral skewness, a root mean square (RMS) band energy, a loudness or total RMS energy, a spectral flatness, a spectral scope, a spectral kurtosis, a spectral flux, a spectral entropy, a spectral autocorrelation function, a normalized variant thereof, or any combination thereof.

35. The method of any one of claims 19-34, wherein the one or more feature comprise one or more temperature features.

36. The method of claim 35, wherein the one or more temperature features comprise one or more of: a depth derivative of temperature with respect to depth, a temperature excursion measurement, a baseline temperature excursion, a peak-to-peak value, a Fast Fourier transform (FFT), a Laplace transform, a wavelet transform, a derivative of temperature with respect to depth, a heat loss parameter, an autocorrelation, and combinations thereof.

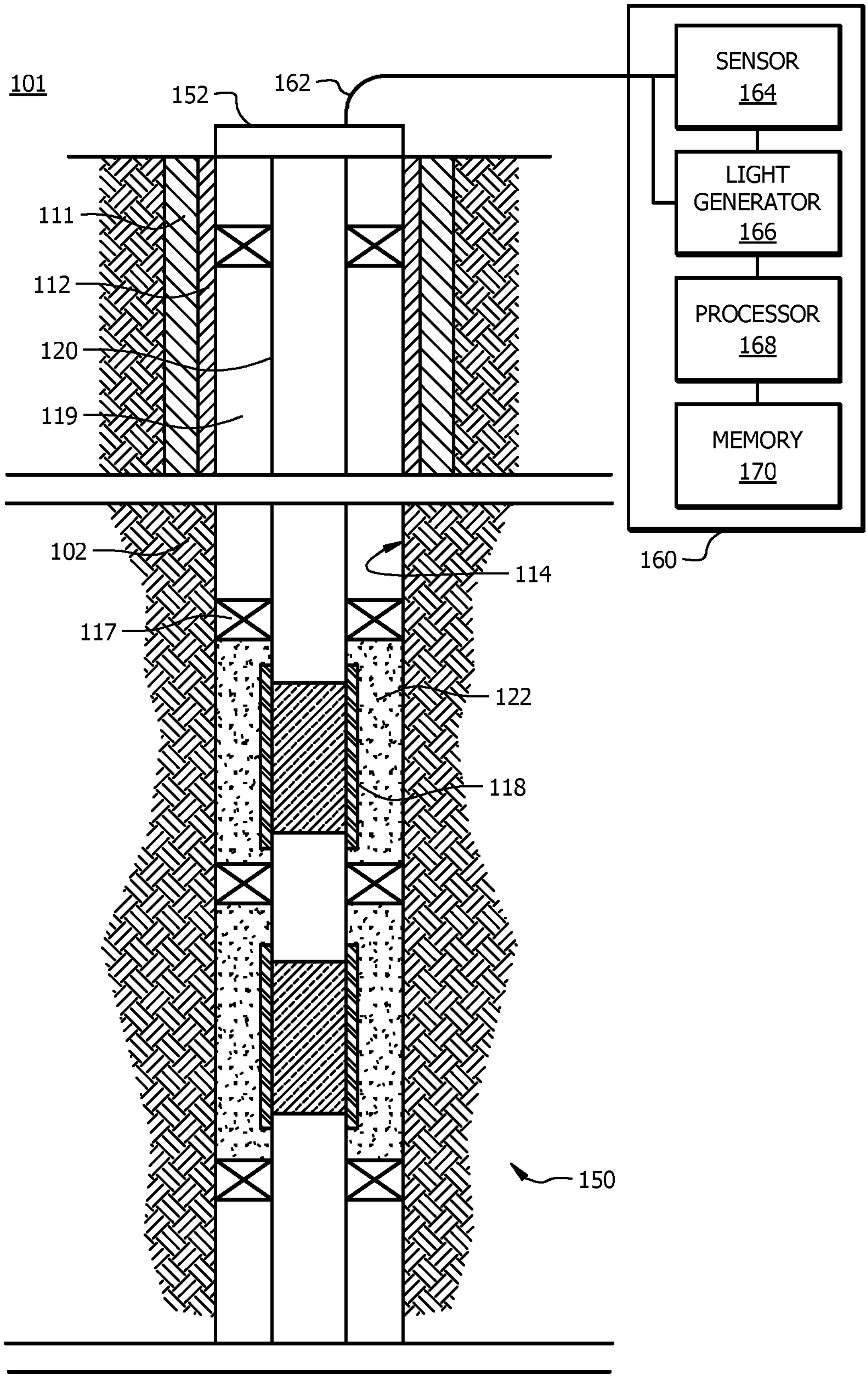
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FIG. 1

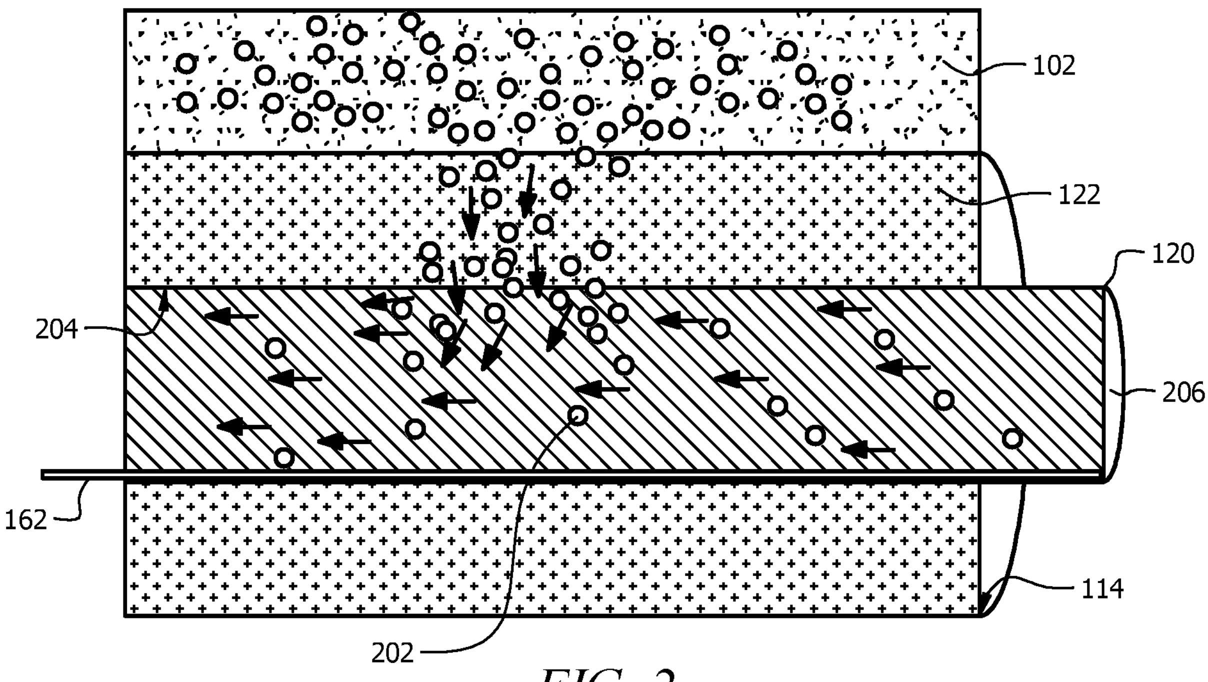


FIG. 2

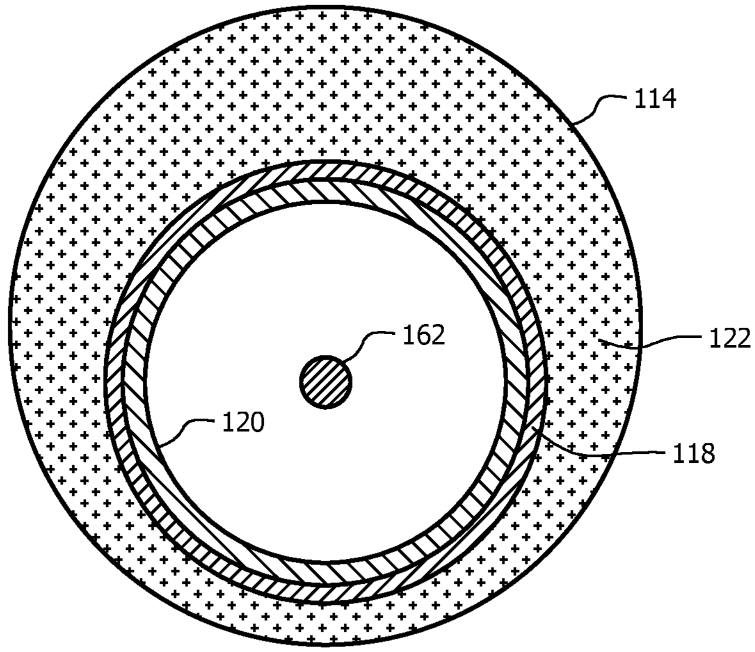


FIG. 3A

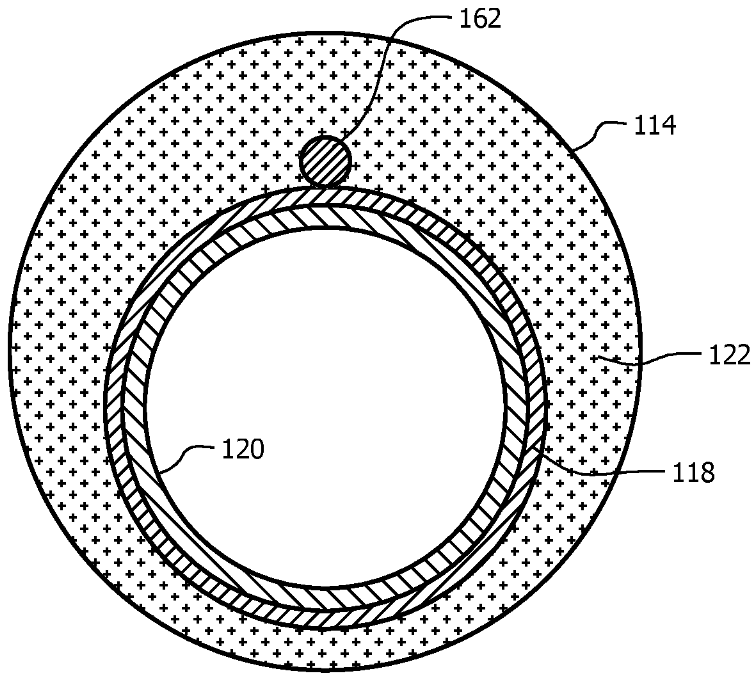


FIG. 3B

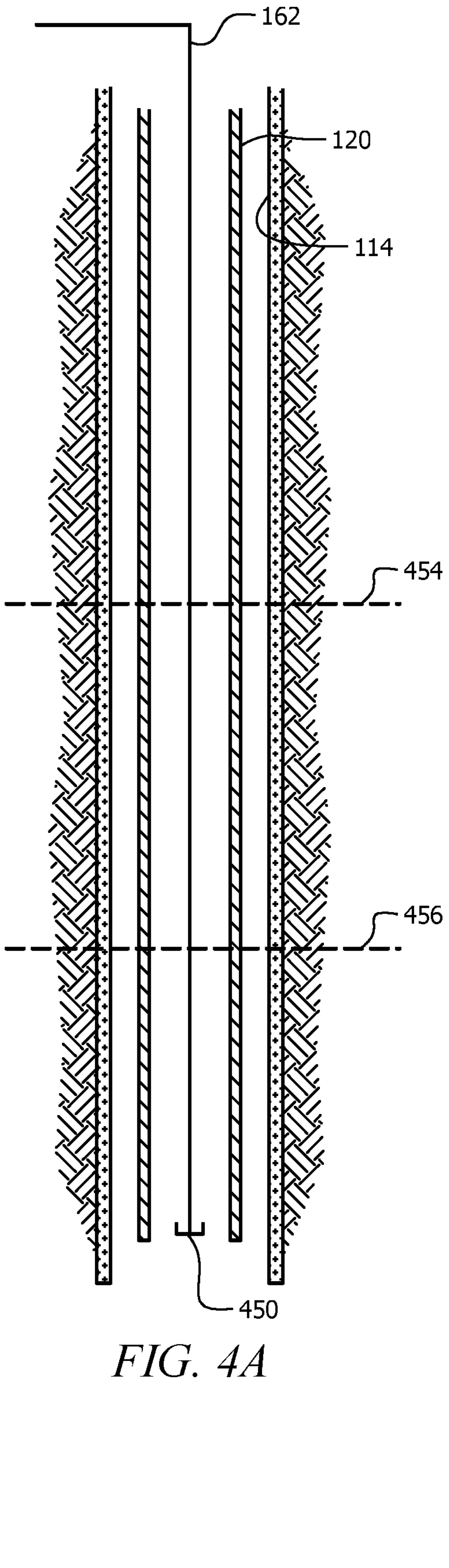


FIG. 4A

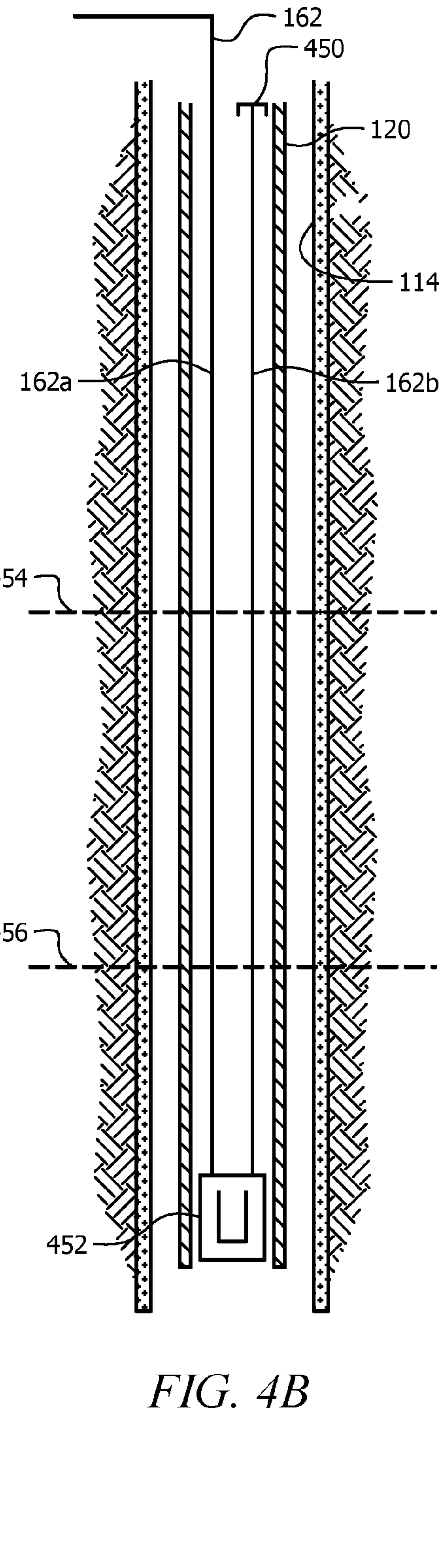
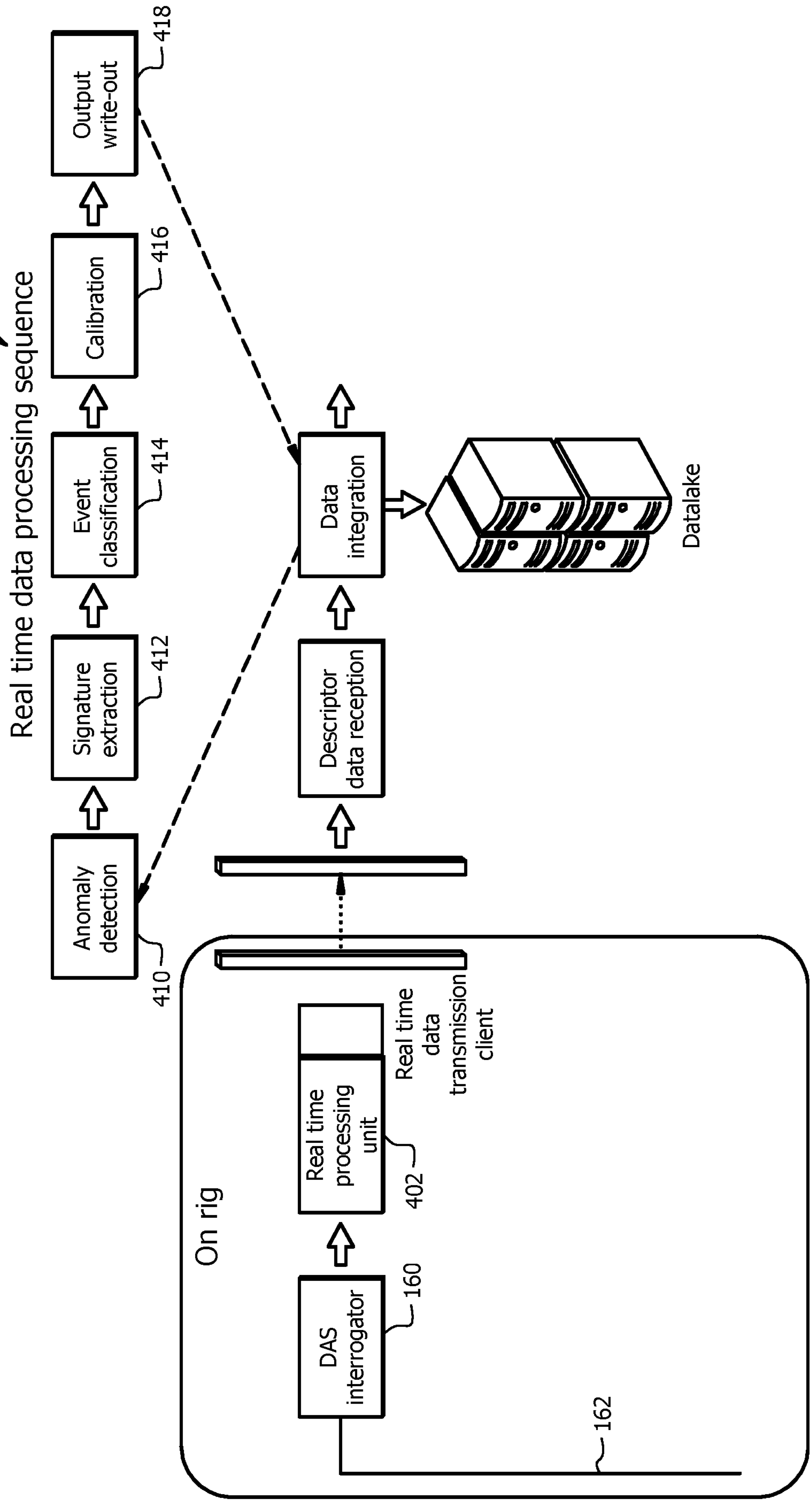


FIG. 4B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Anomaly detection
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Signature extraction
412
Event classification
414
Calibration
416
Output write-out
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Descriptor data reception
Data integration
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On rig
DAS interrogator
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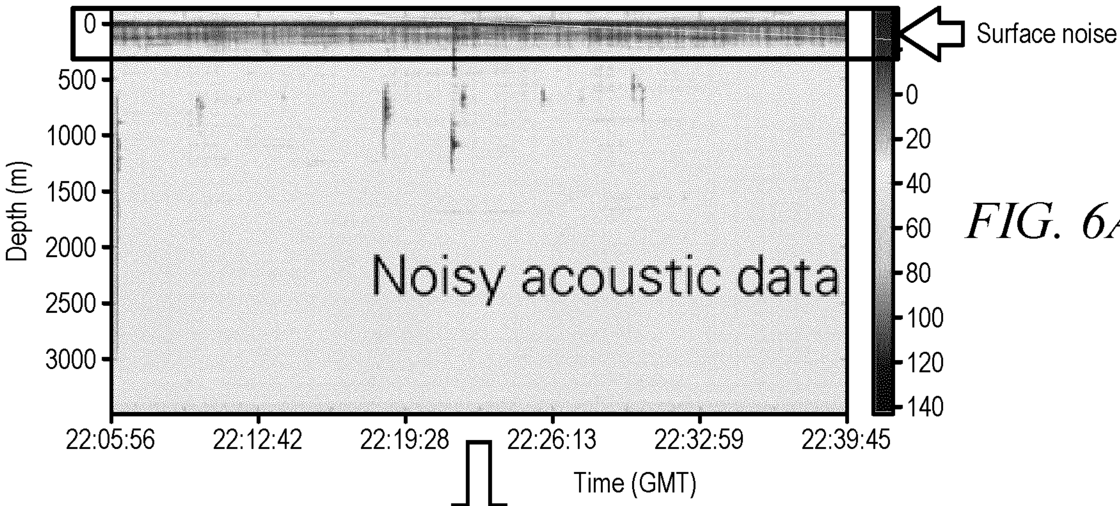
Real time processing unit
402
Real time data transmission client
162

FIG. 5



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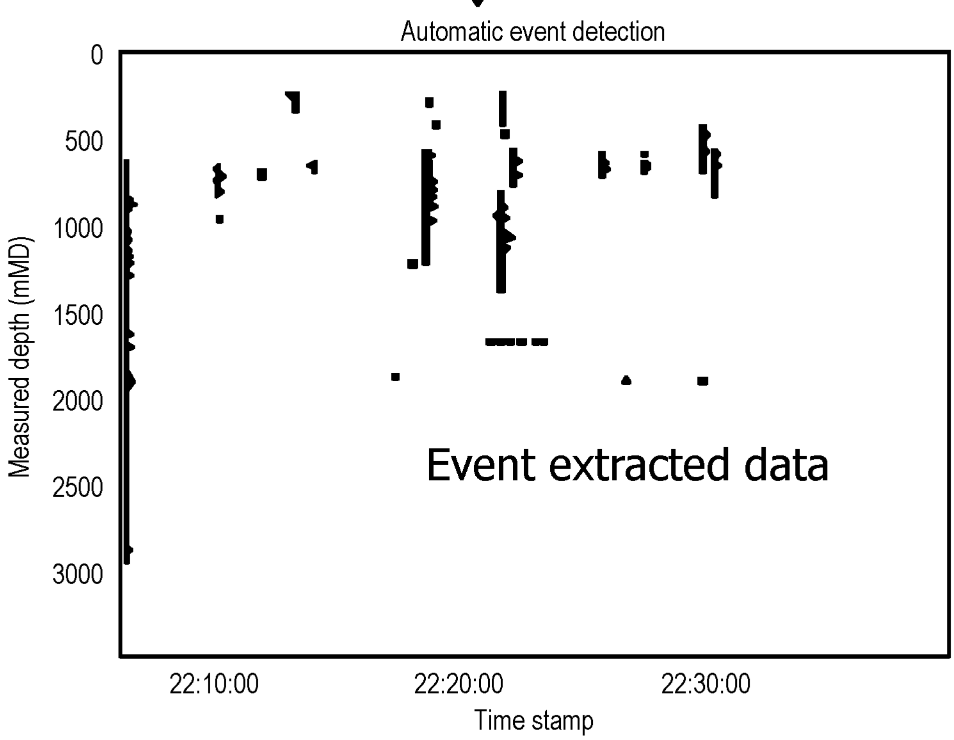
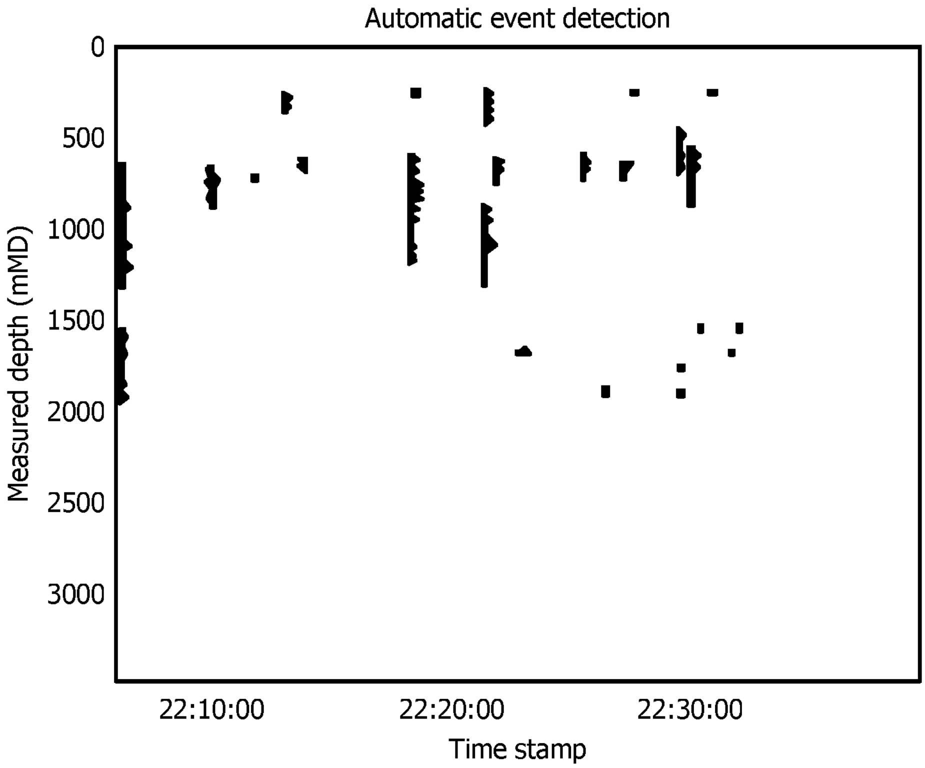
Time (GMT)

FIG. 6A



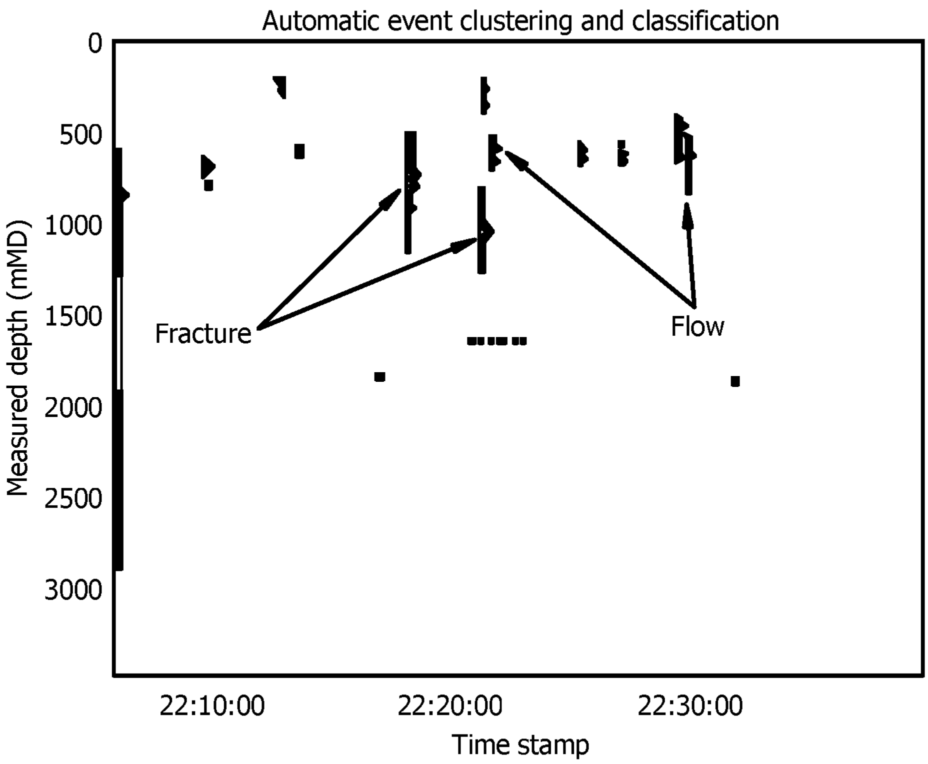
Automatic event detection
0
500
1000
1500
2000
2500
3000
Measured depth (mMD)
Event extracted data
22:10:00
22:20:00
22:30:00
Time stamp

FIG. 6B



Automatic event detection
0
500
1000
1500
2000
2500
3000
Measured depth (mMD)
22:10:00
22:20:00
22:30:00
Time stamp

FIG. 7A



Automatic event clustering and classification
0
500
1000
1500
2000
2500
3000
Measured depth (mMD)
Fracture
Flow
22:10:00
22:20:00
22:30:00
Time stamp

FIG. 7B

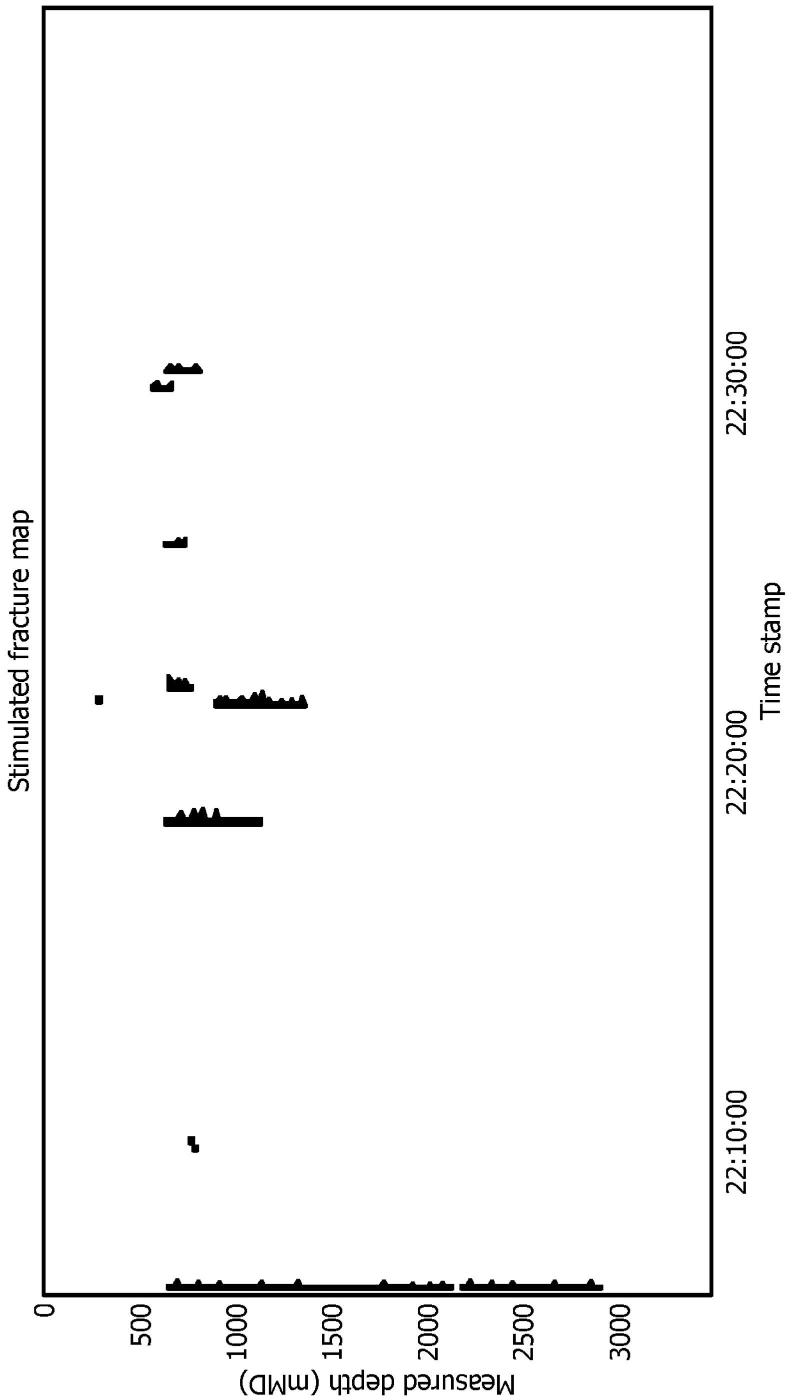

Stimulated fracture map
Time stamp
22:10:00
22:20:00
22:30:00
Measured depth (mMD)
0
500
1000
1500
2000
2500
3000

FIG. 7C

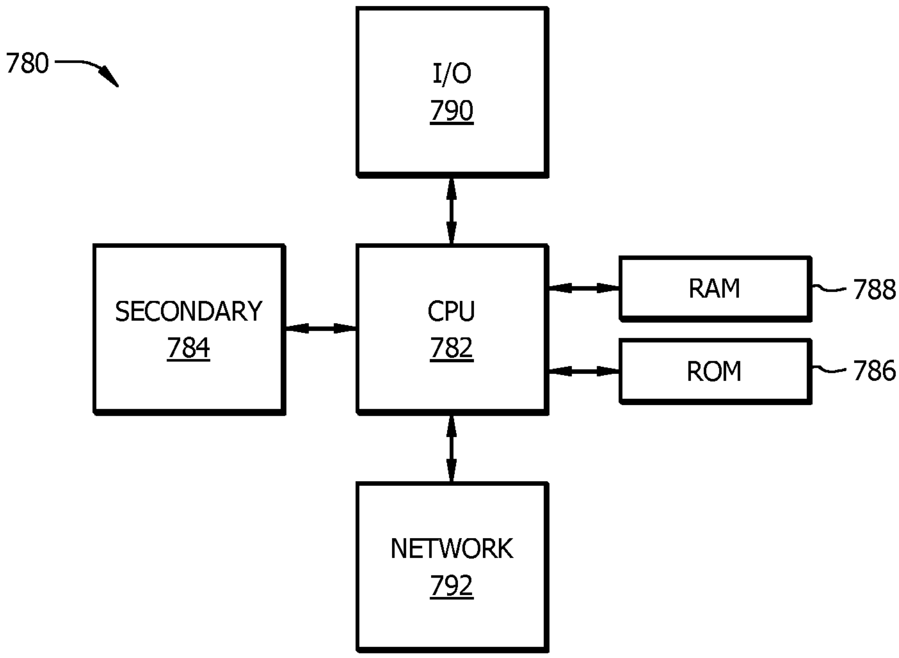


FIG. 8

INTERNATIONAL SEARCH REPORT

International application No
PCT/EP2020/072811

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B47/04 E21B47/12
ADD.

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)
E21B

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

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

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2017/078536 A1 (STATOIL PETROLEUM AS [NO]) 11 May 2017 (2017-05-11)	1-5, 7-23, 25-36
Y	pages 1-25; figures 1-10	5-7, 23-25
X	EP 3 314 308 A1 (SHELL INT RESEARCH [NL]) 2 May 2018 (2018-05-02)	1-4, 8-14, 19-22, 26-32
Y	paragraphs [0001], [0003], [0017], [0020] - [0022], [0025], [0027], [0029] - [0048]; figures 1-5	5-7, 23-25

-/--

[X] Further documents are listed in the continuation of Box C. [X] See patent family annex.

* Special categories of cited documents :

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"P" document published prior to the international filing date but later than the priority date claimed

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

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
28 October 2020	06/11/2020

Name and mailing address of the ISA/	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2, NL - 2280 HV Rijswijk, Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Brassart, P

1

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2019/094140 A1 (HALLIBURTON ENERGY SERVICES INC [US]) 16 May 2019 (2019-05-16) paragraphs [0010], [0014], [0016] - [0020]; figures 1-2 -----	1-5, 7-14, 19-23, 25-32

1

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/EP2020/072811

Patent document cited in search report		Publication date	Patent family member(s)			Publication date
WO 2017078536	A1	11-05-2017	NONE			
EP 3314308	A1	02-05-2018	AU	2016282904	A1	14-12-2017
			BR	112017027708	A2	11-09-2018
			CA	2988953	A1	29-12-2016
			CN	107810431	A	16-03-2018
			EP	3314308	A1	02-05-2018
			US	2019004195	A1	03-01-2019
			WO	2016207341	A1	29-12-2016
WO 2019094140	A1	16-05-2019	FR	3073554	A1	17-05-2019
			WO	2019094140	A1	16-05-2019