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(54) Title: METHOD FOR ASCERTAINING CHARACTERISTICS OF AN UNDERGROUND FORMATION

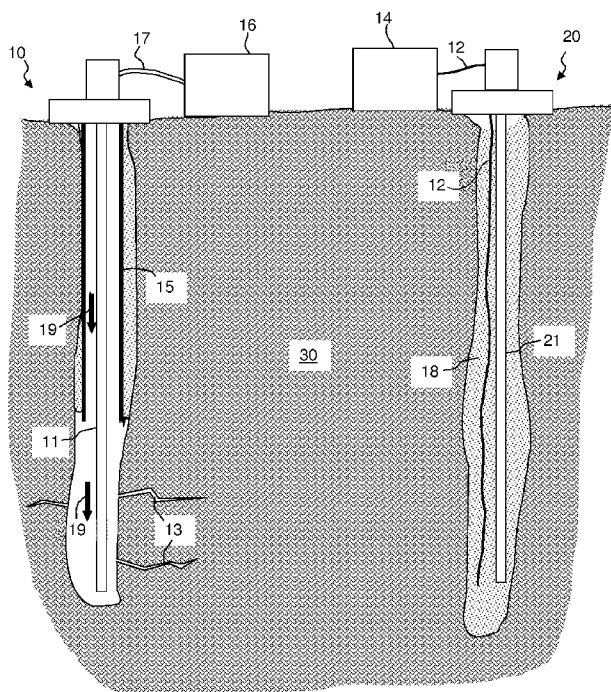


Fig. 1

(57) Abstract: A method for quantitatively measuring acoustic signals to ascertain characteristics of an underground formation. The method includes providing a distributed acoustic sensor in a monitoring well penetrating the formation and initiating a well treatment at a treatment well penetrating the formation. The method also includes observing, via the distributed acoustic sensor, qualitative information about an acoustic signal associated with the well treatment. Based on the quantitative information, a characteristic of the underground formation is inferred.



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METHOD FOR ASCERTAINING CHARACTERISTICS OF AN UNDERGROUND FORMATION

TECHNICAL FIELD

[0001] The present disclosure relates a system and a method for ascertaining characteristics of an underground formation under influence of a well treatment.

BACKGROUND

[0002] In oilfield operations there is often a need to measure changes in formation strain or pressure that occur as a result of well interventions such as hydraulic fracturing and fluid injection. These operations generally create high pressures in the formation, often leading to breakdown (fracturing) of the rock matrix, and may strain the formation in a volume surrounding the intervention. Measurement of this formation strain may be diagnostic of the effectiveness of the intervention and may lead to modification of the intervention parameters that may give significant economic benefit if the measurement technique is inexpensive enough. Changes in strain may occur over time scales ranging from fractions of a second to years and may occur at locations that are far away from the well where the intervention takes place ("treatment well"), often affecting rock volumes intersected by neighboring wells. Similarly, detection of abnormal pressure may indicate fluid paths or potential breakdown or formation/concrete.

[0003] Various methods for applying transducers and/or sensors to a cylindrical structure such as casing and using the sensors or transducers to monitor deformation of the structure as the structure is subjected to various forces are known. For example, U.S. Patent No. 7,245,791 discloses that temperature variations may impart additional strain to an optical fiber and to a supporting structure, such as a well tubular and/or casing, about which the optical fiber is wrapped, and that these temperature variations affect the index of refraction in the optical fiber, so that temperature variations may be considered independently for calibrating the strain measurements.

[0004] A method for monitoring a well treatment is disclosed in US pre-grant publication No. 2013/0298665. This method comprising the steps of:

- installing at least one distributed acoustic strain sensor in at least one monitoring well being at a known distance from the treatment well;
- initiating a well treatment on the treatment well;

- monitoring the formation surrounding the monitoring well using the distributed acoustic strain sensor, involving detecting a change in strain at a first location in the monitoring well with the distributed acoustic strain sensor; and
- using the change in strain to make determinations about the well treatment.

The change in strain is used as indicator that the effect of the well treatment has extended beyond a predetermined preferred treatment zone.

SUMMARY

[0005] In one aspect of the present disclosure, there is provided a method comprising the steps of: a) providing at least one distributed acoustic sensor in at least one monitoring well penetrating an underground formation; b) initiating a well treatment via at least one treatment well penetrating the underground formation; c) observing, via the at least one distributed acoustic sensor, quantitative information about at least one acoustic signal associated with the well treatment; and d) inferring, based on the quantitative information, a characteristic of the underground formation. Preferably, the characteristic of the underground formation that is inferred in step d) is a characteristic that is influenced by the well treatment. The methods described herein may also be used to determine the lateral, horizontal or vertical (formation) extent of the fracture network or induced hydraulic fracture.

[0006] The well treatment may be controlled or ceased based on the inferences made in step d). The present method may be used to determine characteristics of the underground formation between the treatment well and the monitoring well or between any treatment point and any observation point.

[0007] The observing of quantitative information about an acoustic signal associated with the well treatment as recited in step c) may comprise observing amplitude and phase consistent optical responses, generated in a plurality of segments along the distributed acoustic sensor, to an acoustic signal in the underground formation caused by the well treatment, and inferring quantitative information about the acoustic signal from the amplitude and phase consistent optical responses.

[0008] The method may further comprise measuring of temperature at a plurality of points, or distributed temperature, along the monitoring well at the time of observing said quantitative information about the acoustic signal associated with the well treatment.

BRIEF DESCRIPTION OF THE DRAWINGS

[0009] For a more complete understanding of the various features of the present disclosure, reference is made to the accompanying drawings, of which:

[0010] Figure 1 is a schematic illustration of a system in accordance with certain aspects of the present disclosure;

[0011] Figure 2 is a schematic view of a fiber optic cable;

[0012] Figure 3A is a graphical representation of data provided by a distributed acoustic sensor in a monitoring well over a period of time in accordance with certain aspects of the present disclosure; and

[0013] Figure 3B is a graphical representation of flow rate associated with the treatment well over the same period of time indicated in Figure 3A.

DETAILED DESCRIPTION

[0014] The present disclosure relates generally to a system and a method for quantitatively measuring acoustic signals to ascertain characteristics of an underground formation under influence of a well treatment. For example, strain or pressure may be measured in one or more monitoring wells and used to collect information to control processes in a treatment well, or to understand the effectiveness of those treatments. Temperature measurements may be included as well.

[0015] As used herein, “well treatment” refers to any treatment of a well, including completion or recovery processes such as perforation treatments, fracturing, solvent injection, production, or any other fluid injection or removal process that may be carried out on a well. The acronym “DAS” may be used herein, to indicate a distributed acoustic sensor or distributed acoustic sensing.

[0016] It has been found that quantative information about acoustic signals that are associated with a well treatment may be observed via a distributed acoustic sensor that is disposed in a monitoring well that penetrates the underground formation at a distance from the treatment well. Inference of well treatment related characteristics about the underground formation is particularly facilitated by observing amplitude and phase consistent optical responses, generated in a plurality of segments along the distributed acoustic sensor under influence of an acoustic signal in the underground formation that is caused by the well treatment.

[0017] Throughout the present disclosure, terms “amplitude and phase consistent”, “amplitude and phase consistency”, “amplitude and phase integrity”, and “phase and amplitude integrity” are used interchangeably and with the same meaning. Amplitude and phase consistent detection means that there is a causal correlation between the phase and amplitude of the actual acoustic signal and the phase and amplitude responses as detected by the distributed acoustic sensor. Consistency may refer to either channel-consistence, time-consistency, or a combination of both (channel and time integrity). With phase and amplitude consistent detection, the same acoustic signal will produce a response with the same phase and amplitude in each channel regardless of which channel and/or regardless of the time of detection of the acoustic signal. In distributed sensing, a channel is a segment in the distributed acoustic sensor which acts as a sampling bin for collecting responses. The responses from the distributed acoustic sensor are grouped in successive channels, which are essentially processed as discrete responses from an array of discrete “sensors”. When there is phase and amplitude inconsistent data, there is no fixed relationship between the detected phase and amplitude and the actual acoustic signal that gave rise to the inconsistent response. This could be the case if phase and amplitude variations are an artifact of the DAS system itself.

[0018] Distributed acoustic sensors may be deployed in one or more monitoring wells that are located at a distance from the treatment well. Suitably, distributed acoustic sensors are installed in at least two monitoring wells. Each distributed acoustic sensor may comprise an optical fiber disposed in a fiber optic cable, and have an associated laser interrogator unit for sending and receiving optical signals through the optical fiber.

[0019] The distance between the treatment well and the or each monitoring well may typically be in the range of from 50m to 5000m. The proposed acoustical sensing as such does not have a lower limit in terms of range, and thus the distance between the treatment well and any given monitoring well may be less than 50m if the wells can be drilled that close together. While short range of 50m or less is a possibility, one of the benefits of the presently proposed system and methodology is that very small events, such as an onset of fracturing, may be detectable at fairly long range, such as more than 150m, or even more than 300m, away from the monitoring well. Thus a preferred range of distance between the treatment well and any given monitoring well may be from 150m to 5000m, or from 300m to 5000m.

[0020] If more than one monitoring well is used, the wells may be arranged on opposite sides of or evenly spaced about the treatment well, or the monitoring wells may be located in locations determined by the geology and/or topography surrounding the well. If more than one monitoring well is used, it may be possible to collect more data about the subsurface and therefore to provide more useful information.

[0021] Installation of DAS fibers may occur in both a treatment well and in neighboring wells. Laser light enters the fiber above the wellhead and a backscattered signal is measured by optical components at the surface. Known optical time-domain reflectometry (OTDR) methods may be used to infer information strain based on the backscattered signal from a segment of the fiber adjacent to the formation. All depths may be interrogated in the time scale of fractions of a millisecond, providing a virtually instantaneous strain measurement at all depths of interest. Strain/pressure assessments may be performed on many wells at once, providing a sampling of the volume strain or pressure over potentially a large area. The measurements may be used to diagnose and correct a geomechanical model or may be used to directly intervene in the treatment with or without integration with other measurements.

[0022] By way of example only, referring initially to Figure 1, a treatment well 10 and a monitoring well 20 may be located according to a predetermined plan. Both the treatment well and the monitoring well penetrate an underground formation 30. The treatment well may be one in which a well treatment such as fracturing or other injection operation may be performed. Such injection operation may include injection of a fluid into the formation 30 by pumping the fluid into the treatment well 10. A fluid supply unit 16, which may include one or more fluid pumps (not shown), may be configured in fluid communication with the treatment well 10 via an optional fluid supply line 17. In some cases, the well treatment may include pumping fluid into the treatment well 10 at sufficiently high pressure to fracture the formation 30 adjacent to the treatment well 10, as illustrated by arrows 19. The treatment well 10 may contain one or more tubulars 11 and may be cased with casing 15, as shown. Likewise, the monitoring well 20 may contain one or more tubulars 21 and/or casing, notwithstanding that monitoring well 20 as depicted in the example of Figure 1 has no casing.

[0023] One or more fiber optic cables 12 designed to collect distributed strain measurements may be deployed in monitoring well 20 and coupled to the formation by any suitable means. As illustrated, monitoring well 20 has been cemented with the fiber optic cable 12 embedded in the cement 18. It will be understood that the fiber optic cable 12 may

also be clamped or bonded to a downhole tubular, or acoustically coupled to the formation 30 by any other means. The fiber optic cable 12 comprises at least one optical fiber. One or more light boxes 14 containing laser light sources and signal-receiving means may be optically coupled to the optical fiber at the surface. The cable may be double-ended, i.e. may be folded back in the middle so that both ends of the cable are at the source, or it may be single-ended, with one end at the source and the other end at a point that is remote from the source. The length of the cable may range from a few meters to several kilometers, or even hundreds of kilometers. In either case, measurements may be based solely on backscattered light, if there is a light-receiving means only at the source end of the cable, or a light receiving means may be provided at the second end of the cable, so that the intensity of light at the second end of the fiber optic cable may also be measured.

[0024] A schematic view of a non-limiting embodiment of a fiber optic cable 12 is shown in Figure 2 to illustrate a number of options. The fiber optic cable 12 may comprise a plurality of optical fibers, which when used simultaneously can enhance the signal to noise ratio. Two straight longitudinal optical fibers 40a are shown in Figure 2 as an example, but more may be provided, or only one. Alternatively, or in addition thereto, optical fibers may be configured within the fiber optic cable 12 in a non-straight configuration, such as undulating in a plane, or helically wound around a core 45. Helically wound optical fiber 40b is an example of such non-straight configured optical fiber. Regardless of the type of configuration, the optical fibers may be embedded in protective materials, and covered by one or more protective out layers. One protective outer layer 42 is shown as an example. A non-straight optical fiber configuration, such as the helically wound optical fibers 40b, provides a different sensitivity to formation strain and/or acoustic signals than straight longitudinal optical fibers 40a.

[0025] The light source may be a long coherence length phase-stable laser and may be used to transmit direct sequence spread spectrum encoded light down the optical fiber. Localized strain or other disruptions may cause small changes to the optical fiber, which in turn may produce changes in the backscattered light signal. The returning light signal thus may contain both information about strain changes and location information indicating where along the fiber they occurred. The location along the fiber may be determined using spread spectrum encoding, which may uniquely encode the time of flight along the length of the fiber.

[0026] Preferred embodiments of the invention involve observing amplitude and phase consistent optical responses with distributed acoustic sensing by means of the fiber optic cable. More preferred embodiments of the invention involve observing amplitude and phase consistent optical responses with DAS of low frequency acoustic signals in the formation. In this context, low frequency may mean a frequency in a range of from 0 Hz to 20 Hz, preferably in a range of from 0 Hz to 5 Hz. The lower limit of 0 Hz is used to indicate that there is no inherent lower limit, but the detection might in practice be limited to a value just above 0 Hz, such as 10^{-3} Hz, 10^{-2} Hz, 10^{-1} Hz, or 1 Hz, depending on the stability of the DAS system itself and its deployment in the well.

[0027] Systems and services to acquire phase and amplitude consistent DAS data with fiber optic cables are available in the market. For example, as confirmed in the April 2013 issue of InnovOil, page 24, OptaSense, has announced that its fiber-optic DAS system and services, with consistent frequency, phase and amplitude response, are available to companies throughout the oil and gas industry. It has now been found that amplitude and phase consistent data from a distributed acoustic sensor allows the interpreter to infer much more quantitative information about the acoustic signal than was hitherto possible due to inconsistency of the phase and amplitude in conventional fiber optic sensing and/or due to the relatively small aperture (length) of a conventional seismic array of geophones or hydrophones. If phase and amplitude of responses are varying independently from the acoustic signals in the formation, then less quantitative information can be inferred about the acoustic signals and the characteristics of the formation. Distributed acoustic sensing with an optical fiber provides the possibility to ‘listen’ in all points along the entire length of the fiber optic cable in the well (from surface to bottom, if desired). It has been contemplated that by having amplitude and phase consistent DAS data it is possible to determine how effective a fracture is, even though the treatment well may be at a distance of more than 50m or even more than 150m or more than 300m from the DAS system. It has been contemplated that by having amplitude and phase consistent distributed acoustic data it is possible to determine how effective a fracture is even when no micro-seismic is available. There is even been found circumstantial evidence that the onset of a fracture may already be inferred from amplitude and phase consistent DAS data before the fracture has actually initiated.

[0028] When it is desired to make measurements, the light source may transmit at least one light pulse into the end of the fiber optic cable and a backscattered signal may be received at the signal-receiving means. Known optical time-domain reflectometry (OTDR) methods may be used to infer formation strain or other characteristics based on the backscattered signal from one or more segments of the fiber adjacent to the formation of interest.

[0029] Formation strain, pressure, or other characteristics may be inferred based on readings observed in the monitoring well(s) or treatment well(s) over the duration of the treatment process and, if desired, for a period of time thereafter, providing information about changes in the formation strain or pressure over time. Of particular interest are strain measurements which may indicate whether the effect of the injection in the treatment well has extended to or beyond the limit of a predetermined preferred treatment zone. Thus, for example, strain in the formation resulting from the injection of fluid may be detected by fiber optic cable 12 for at least the duration of the injection. In addition, acoustic events attributable strain-induced fractures 13 may also be detectable by fiber optic cable 12.

[0030] Similarly, measurements in a pressurized zone may be used to sense movement of a pressure front. Pressure in the formation may cause a dilation in the matrix, i.e. an isotropic strain in all directions. A fiber oriented in any direction may pick this up as long as it passes through a region of changing pressure – the “pressure front.”

[0031] All depths may be interrogated in the time scale of fractions of a millisecond, providing a virtually instantaneous strain measurement at all depths of interest. Strain, pressure, and/or other assessments may be performed on many wells at once, providing a sampling of the volume strain over potentially a large area. The measurements may be used to diagnose and correct a geomechanical model or may be used to directly intervene in the treatment with or without integration with other measurements. Thus, pressures may be controlled to reduce out-of-zone effects and a better understanding of production may be attained given the measured connectivity.

[0032] In addition to the foregoing, it has been observed that strain anomalies typically travel from the treatment well to neighboring wells and that, shortly after the strain anomaly reaches a neighboring well, it travels up and down that wellbore, creating pressure connectivity over a significant vertical column (as measured using pressure gauges in the field data). This may be undesirable for optimal production of the zones. It may be possible to monitor the treatment

using DAS signals in the monitoring wells and to stop pumping when initial inter-well connectivity is established.

[0033] The present methods are believed to have no inherent lower limit to the frequency of investigation and are therefore may be limited only by the stability of the hardware over long time scales. There are various methods of backscatter measurement, including the use of Rayleigh and Brillouin backscattering, and one method may be preferred over others for this implementation of the present disclosure, especially at low frequency.

[0034] These low frequency signals may be measured with phase and amplitude integrity, allowing quantitative measurements which can be used to infer characteristics of the formation. For example, predictive statements may be made about the flow of the monitoring well and quality of hydraulic fractures. For example, the length of time over which an acoustic signal is observed after a hydraulic fracture has stopped may be indicative of the subsequent flow associated with that hydraulic fracture stage. Additionally, the number of distinct acoustic signals observed may provide an indication of which perforations preferentially took the fracture fluid. The methods herein may also provide an indication of whether wells are in hydraulic communication and when the subsurface around the fibered monitoring well is accepting fluid or pushing fluid out. The number of distinct acoustic signals on a fibered monitoring well may also provide an indication of how many perforations have been initiated on a treatment well and which ones preferentially took more or less of the fracture fluid. By combining and comparing DAS measurements taking during the treatment of the treatment well and using the DAS monitoring well measurements it may be possible to measure which fractures of the wells are in hydraulic communication during the hydraulic fracture treatment. Such determination may involve applying phase, amplitude and frequency processing over a long duration of time, e.g., days. Once pumping has ceased, it may be possible to predict which of the hydraulic fractures from the treatment well will stay connected with fractures from the fibered monitoring well and will thus remain in communication during production of the treatment well and will show production interference. Moreover, it may be possible to determine when the subsurface around the monitoring well is accepting fluid or pushing fluid out during and after the hydraulic fracture stimulations of the treatment well.

[0035] One method may include the steps of providing a DAS in a monitoring well penetrating an underground formation, initiating a well treatment in a treatment well penetrating the underground formation, and observing, via the DAS, information about an

acoustic signal associated with the well treatment. That observed information may be quantitative information allowing for an inference about a characteristic about the underground formation.

[0036] Referring now to Figures 3A and 3B, information about one or more acoustic signals may be plotted in a manner that highlights one or more quantitative features. Figures 3A and 3B illustrate an example of a single well treatment over a period of time. Figure 3A shows information retrieved from the DAS installed in a monitoring well over a time period and Figure 3B shows pump rates into a treatment well over the same period of time. The monitoring well was about 200m separated from the treatment well. As illustrated, one well treatment may be associated with a number of different events, illustrated as 100, 200, 300, 400, 500, any or all of which may be of interest in ascertaining characteristics of the formation.

[0037] The timing and nature of these events may be inferred on the basis of quantitative information. For instance the first event 100 may be delineated from the time preceding the first event 100 by noting the presence of acoustic signals, or a change in acoustic signal readings as compared to an ambient, or steady state reading. The events may each have quantitative information associated therewith. For example, the length of time 101 of the acoustic signal associated with the first event 100 is noted, along with the amplitude 102 or width of the acoustic signal. An indication of a frequency or strength of the acoustic signal is illustrated by the strength of shading in Figure 3A. Other quantitative information may include a length of time between the initiation of the well treatment and an initial observation of the acoustic signal, distance between acoustic signals, or any other quantifiable observation based on the acoustic signal. From the quantitative information, it may be apparent when the second event 200 occurs, even if the pump rate illustrated in Figure 3B were unknown. Specifically, in the example, because the strength of the shading indicates a notable change in frequency, it may be clear that a ball was dropped. Further, a noticeable reduction in the amplitude 202 of the acoustic signal may be observed, also having the possibility of indicating an event horizon. The change of strength in the shading after a time 201 may readily indicate a frequency change signaling the end of the second event 200 and the beginning of the third event 300. Likewise, additional event horizons may be apparent. For example, event 300 may end after a time 301, as apparent by the frequency change indicated by the change in intensity of shading after the time 301 and/or

by the single width 302 becoming two widths 403A and 403B. These two widths 403A and 403B may represent two distinct acoustic signals, such as might be expected with two fracture arms radiating from the treatment well. Thus, the presence of a particular number of acoustic signals may be indicative of the type of event occurring. Thus, event 300 might represent the time the fracturing fluid is being pressurized. Similarly, the change in frequency after time 401 may indicate an event horizon whereby fractures are no longer opening but begin closing with the initiation of event 500.

[0038] Notably, some of the event horizons can be easily tested against known data, using time measurements. For example, the length of time 101 of observation of the acoustic signal of event 100 aligns nicely with the known length of time 105 of a pressure test. Likewise, the event 200 aligns nicely with the known timing 205 of a ball drop.

[0039] Once characteristics have been inferred from the quantitative information, the well treatment may be modified accordingly. Thus, in addition to the steps described above, a step of controlling the well treatment may be included to allow for improved well treatments based on actual information from the underground formation. In some instances, the characteristics inferred from the quantitative information may provide the basis for ceasing the well treatment. For example, if the quantitative information provides an indication that fractures are closing, pumping may be stopped.

[0040] Likewise, the inferred characteristic may be used to predict an outcome of a planned additional well treatment in the treatment well and/or monitoring well. Such outcome may include a parameter relating to the effectiveness of the planned well treatment. For example the parameter may include a flow rate of fluid from the underground formation into the treatment well, or any other relevant flow rate. Based on that predicted outcome, the planned well treatment may be altered and an alternate plan may be executed in place of the originally planned well treatment.

[0041] In one example, a well treatment may be conducted at an additional well penetrating the underground formation, with either or both of the prior described wells serving as monitoring wells. The DAS in the monitoring well(s) may be used to observe quantitative information about an additional acoustic signal associated with the well treatment and the additional well treatment. The quantitative information about the additional acoustic signal from the additional well may be used to infer another characteristic of the formation or the

information may be used in combination with the prior described signals to provide a better indication of the characteristic of interest.

[0042] Additionally or alternatively, a DAS sensor may be provided in the treatment well, and original or additional acoustic signals may be observed from the treatment well. If other acoustic signals have been observed elsewhere, the additional acoustic signals observed in the treatment well may be compared with the acoustic signals from the monitoring well(s), which may provide a better indication of the characteristic of interest. Accordingly, the method described herein may further comprise:

- e) providing an additional distributed acoustic sensor in the treatment well;
- f) observing, via the additional distributed acoustic sensor in the treatment well, an additional acoustic signal associated with the well treatment in the treatment well; and
- g) comparing the observed acoustic signal with the observed additional acoustic signal.

[0043] In some instances, multiple well treatments may occur in different wells while the DAS in the monitoring well collects acoustic signals, allowing for underground formation to be observed. In particular, observation of multiple well treatments, whether simultaneous, overlapping, or serial, may provide a better indication of the characteristic of interest by providing an indication of interplay between wells. Accordingly, the method described herein may further comprise:

- e) conducting a well treatment at a third well penetrating the underground formation;
- f) observing, via the distributed acoustic sensor in the monitoring well, quantitative information about an additional acoustic signal associated with the well treatment at the third well; and
- g) inferring, based on the quantitative information about the additional acoustic signal, another characteristic of the formation.

[0044] Similarly, the DAS in the monitoring well may collect acoustic signals of serial well treatments in a single well to provide a better indication of the characteristic of interest by providing an indication of cumulative effects of the well treatments.

[0045] The technology described herein is particularly (but not exclusively) suitable for investigation of strain fronts caused by well treatments. Hitherto, micro-seismic detection

has been the main source of monitoring information. The dominant frequency range characteristic of micro-seismic signals is typically between about 20 Hz and about 500 Hz and for this reason micro-seismic events are typically measured within this frequency range. Selecting frequencies below 20 Hz is contemplated to be advantageous for investigating strain fronts. Notwithstanding, amplitude and phase consistent detection may also benefit detection of other physically induced events, including micro-seismic studies. Such events may be harder to detect if the phase is varying from trace to trace, especially if the signal is close to the noise floor.

[0046] Strain fronts are predominantly acoustic, but it has been found they may also include temperature effects. For this reason, it is contemplated that more can be deduced about the nature of the strain front and the characteristics of the underground formation when temperature effects are incorporated into the method. This may include measuring temperature at a plurality of points, or distributed temperature, along the monitoring well at the time of observing said quantitative information about the acoustic signal associated with the well treatment. The inference of the characteristic of the formation may subsequently be based on the quantitative information observed about the acoustic signal combined with the temperature along the monitoring well as measured. Temperature along the monitoring well may suitably be measured using the DAS fiber that is used for observing the quantitative information about the acoustic signal. This requires processing of the data to separate out temperature effects from the responses to the acoustic signals. Such additional data processing may be avoided by providing a separate array of temperature sensors or a separate distributed temperature sensor in the monitoring well, in addition to the DAS sensor.

[0047] The particular examples disclosed above are illustrative only, as the present claimed subject matter may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative examples disclosed above may be altered or modified and all such variations are considered within the scope and spirit of the present claimed subject matter. By way of example only, one of skill in the art will recognize that the number and location of the monitoring well(s) with respect to the first well, the number and configuration of cables and sensors, the sampling rate and

frequencies of light used, and the nature of the cable, coupling devices, light sources, light signals, and photodetectors may all be modified within the scope of the present disclosure. Similarly, while examples are provided for qualitative information, it is noted that other types of qualitative information may also be observed. Further, while specific examples of characteristics are given, other characteristics may be inferred without departing from the spirit of the present disclosure. Moreover, it will be appreciated that such a development effort might be complex and time-consuming, but would nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of the present disclosure.

[0048] Some portions of the present disclosure provide a system and method for quantitatively measuring formation strain or other characteristics in a volume around the treatment well. The method may be practised as an *in-situ* permanent method. Portions of the instant disclosure may relate to, or be used for, time-lapse measurement of either proximal and/or distal strain or pressure, in the underground formation before, during, and after production operations. Strain measurements may be taken over long periods of time—seconds/minutes/days/weeks/months/years—giving them greater scope than normal seismic data.

[0049] The subject matter of the present disclosure is described with specificity. However, the description itself is not intended to limit the scope of the claimed subject matter. The claimed subject matter, thus, might also be embodied in other ways to include different steps or combinations of steps similar to the ones described herein, in conjunction with other present or future technologies. Moreover, although the term “step” may be used herein to connote different methods employed, the term should not be interpreted as implying any particular order among or between various steps herein disclosed except when the order of individual steps is explicitly described.

[0050] For illustrative purposes only, two examples of implementation of the inventive concepts are set forth below.

Example 1: Hydraulic Fracturing

[0051] According to a first example, distributed OTDR sensing may be used to detect hydraulic fracturing according to the following workflow:

- deploy one or more DAS fibers in one or more wells in the vicinity of an intended hydraulic fracturing operation;

- prior to hydraulic fracturing in the area, record noise levels along the fiber as a control measurement;
- upon initiation of pumping of fracture fluids, for any or all fracture stages and fluid types, including mini-frac (or test frac), record the strain field as measured by the DAS system, for all locations in the well where the formation may be affected by the fracture operation;
- simulate the strain field as a function of time and space using a geomechanical simulation;
- from the results of the simulation, make a prediction of the axial strain measurements at the places where the DAS fibers have made the measurements;
- compare the predictions and measurements and adjust the geomechanical model parameters to minimize the difference;
- use the new geomechanical model to make further predictions that may be compared with DAS (or other) measurements;
- use the new geomechanical model to optimize perforation locations and pumping schedule (and any other relevant parameters) such that the predictions of the updated model, with the new perforation locations and pumping schedule, predict optimal production over the life of the field; and
- keep the geomechanical model evergreen by including data from either infill hydraulic fracturing, recompletion fractures, long-term depletion or other changes in formation strain due to production operations.

[0052] The foregoing workflow may be generalized beyond hydraulic fracture detection to include any earth motion that may be measured with DAS, including but not limited to pressure or radial strain.

Example 2: Depletion

[0053] According to a second example, the inventive methods are used to measure time-dependent strain in a depleting field. More specifically, the inventive methods provide a way to measure moderate resolution differential depletion in a reservoir. The cost and availability of fiber optic sensors, allows construction of an areal picture of depletion induced strain.

[0054] Thus, according to this example, distributed OTDR sensing may be used to detect and monitor field depletion according to the following workflow:

- deploy one or more DAS fibers in one or more wells in the vicinity of an intended hydraulic fracturing operation;
- prior to field startup, record noise levels along the fibers as a control measurement;
- upon initiation of field depletion, the strain field as measured by the DAS system, for all instrumented wells;
- simulate the strain field as a function of time and space using a geomechanical simulation;
- from the results of the simulation, make a prediction of the axial strain measurements at the places where the DAS fibers have made the measurements;
- compare the predictions and measurements and adjust the geomechanical model parameters to minimize the difference therebetween;
- make changes in the model as required to match the data highlight differences in subsidence/depletion for different parts of a formation, leading to localized interventions;
- alternatively, depleted/depleting areas may be obvious even without the benefit of a geomechanical model as areas with greater or lesser strain changes;
- if the fiber is also configured to measure formation pressure, a measure of rock compressibility might be possible from strain and pressure.

[0055] While the invention may have the particular advantaged described above, it may be used advantageously to detect inter-well effects caused by other sources and may be used to determine information about properties of the formation between wells. Accordingly, the protection sought herein is as set forth in the claims below.

WHAT IS CLAIMED IS:

1. A method comprising:
 - a) providing a distributed acoustic sensor in a monitoring well penetrating an underground formation;
 - b) initiating a well treatment via a treatment well penetrating the underground formation;
 - c) observing, via the distributed acoustic sensor, quantitative information about an acoustic signal associated with the well treatment; and
 - d) inferring, based on the quantitative information, a characteristic of the underground formation.
2. The method of claim 1, wherein the monitoring well is located at a distance from the treatment well.
3. The method according of claim 1 or 2, wherein the distributed acoustic sensor comprises an optical fiber disposed in a fiber optic cable.
4. The method of any one of the preceding claims, wherein the well treatment comprises a fracture treatment.
5. The method of any one of the preceding claims, wherein the well treatment comprises a perforation treatment.
6. The method of any one of the preceding claims, further including the step of controlling the well treatment based on the inference made in step d).
7. The method of any one of the preceding claims, further including the step of ceasing the well treatment based on the inference made in step d).
8. The method of any one of the preceding claims, wherein the quantitative information comprises a length of time over which the acoustic signal is observed.

9. The method of any one of the preceding claims, wherein multiple acoustic signals are observed and wherein the quantitative information comprises the number of acoustic signals.
10. The method of any one of the preceding claims, wherein the quantitative information comprises a frequency of the acoustic signal.
11. The method of any one of the preceding claims, wherein the quantitative information comprises a length of time between the initiation of the well treatment and an initial observation of the acoustic signal.
12. The method of any one of the preceding claims, wherein the quantitative information comprises an amplitude of the acoustic signal.
13. The method of any one of the preceding claims, wherein the quantitative information comprises a phase of the acoustic signal.
14. The method of any one of the preceding claims, further comprising predicting, based on the inferred characteristic, an outcome of a planned additional well treatment in the treatment well.
15. The method of claim 14, wherein the outcome comprises a parameter relating to effectiveness of the planned additional well treatment in the treatment well.
16. The method of claim 15, wherein the parameter comprises a flow rate of fluid from the underground formation into the treatment well.
17. The method of any one of claims 14 to 16, further comprising:
 - based on the outcome, altering the planned additional well treatment resulting in an altered additional well treatment plan; and
 - executing the altered additional well treatment plan in the treatment well.

18. The method of any one of the preceding claims, wherein said observing, via the distributed acoustic sensor, of quantitative information about an acoustic signal associated with the well treatment as recited in step c) comprises observing amplitude and phase consistent optical responses, generated in a plurality of segments along the distributed acoustic sensor, to an acoustic signal in the underground formation caused by the well treatment, and inferring quantitative information about the acoustic signal from the amplitude and phase consistent optical responses.

19. The method of any one of the preceding claims, wherein the acoustic signal has a frequency of in a range of from 0 Hz to 20 Hz.

20. The method of any one of the preceding claims, further comprising measuring temperature at a plurality of points, or distributed temperature, along the monitoring well at the time of observing said quantitative information about the acoustic signal associated with the well treatment, and wherein the inference in step d) is based on the quantitative information and the temperature along the monitoring well as measured.

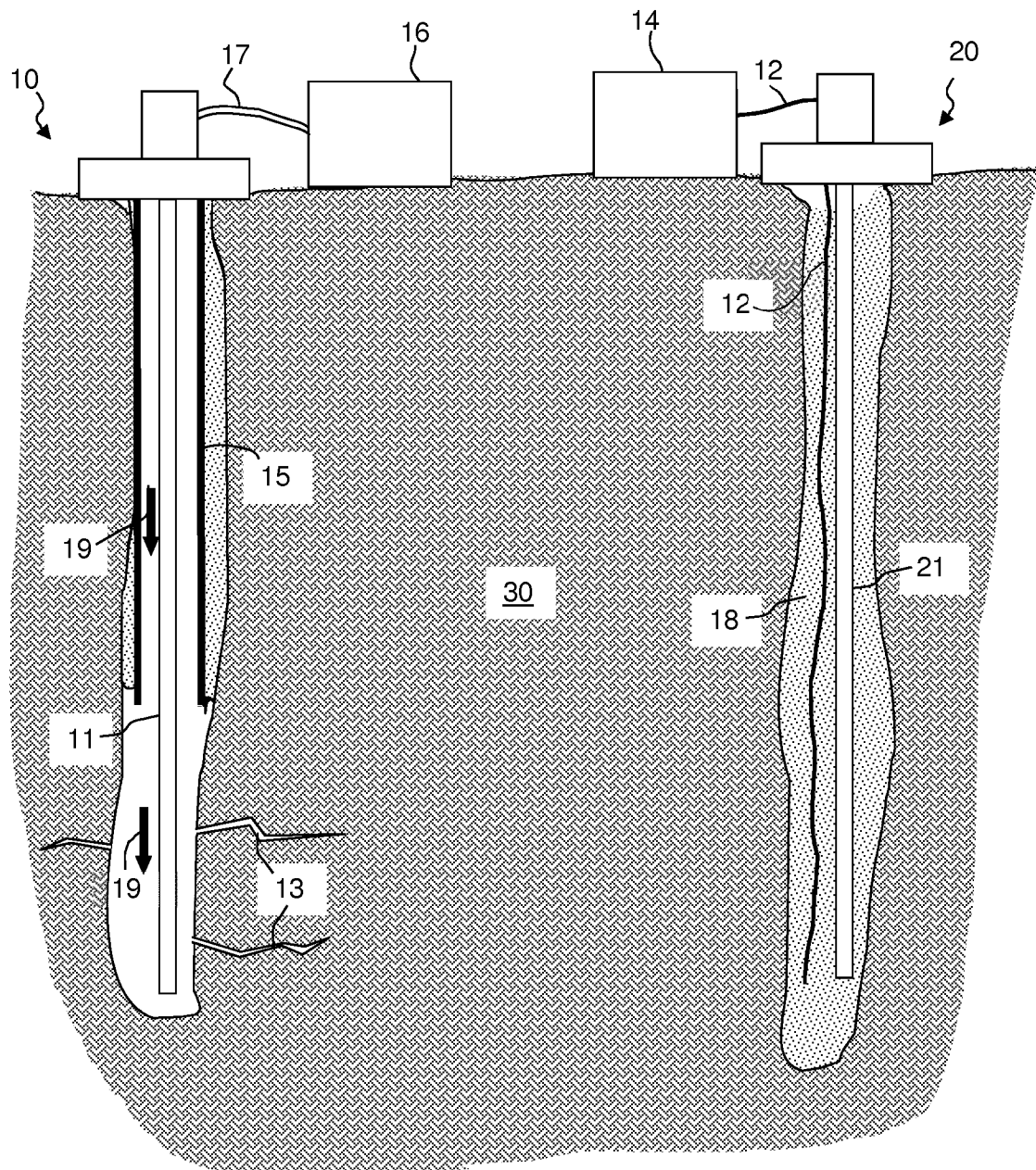
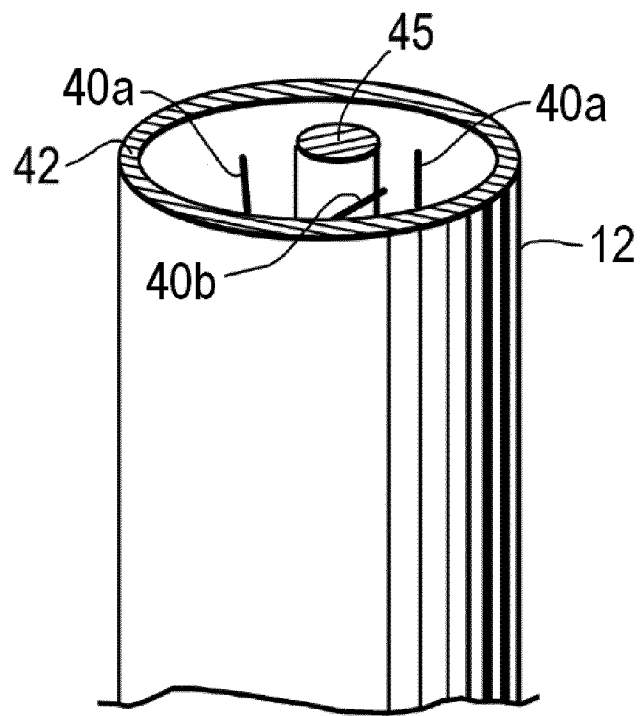
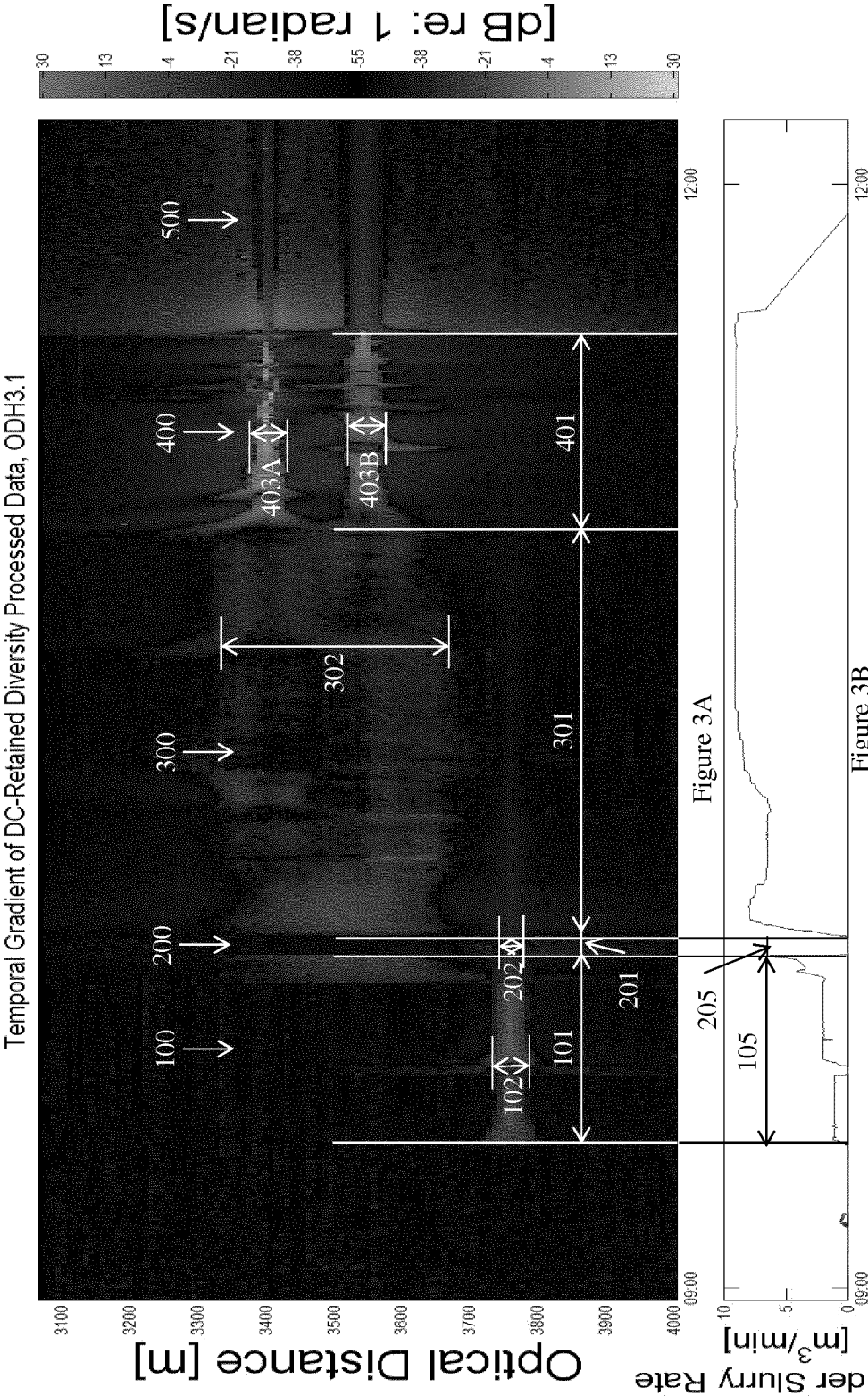


Fig. 1

Fig.2





INTERNATIONAL SEARCH REPORT

International application No
PCT/EP2015/079162

A. CLASSIFICATION OF SUBJECT MATTER
INV. G01V1/22 G01V1/42 G01V8/02 E21B47/12 G01V8/24
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)
G01V 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	US 2013/298665 A1 (MINCHAU MICHAEL CHARLES [CA]) 14 November 2013 (2013-11-14) cited in the application	1-9,11
Y	the whole document	14-17,20
X	US 2014/334253 A1 (LUMENS PAUL GERARD EDMOND [NL] ET AL) 13 November 2014 (2014-11-13) paragraphs [0001], [0023], [0043], [0046] - [0048], [0051]	1,9-13, 18,19
Y	US 2011/088462 A1 (SAMSON ETIENNE M [US] ET AL) 21 April 2011 (2011-04-21) paragraphs [0019], [0023] - [0025], [0032] - [0036], [0040], [0045], [0046]	14-17,20



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents :

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"&" document member of the same patent family

Date of the actual completion of the international search

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No

PCT/EP2015/079162

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