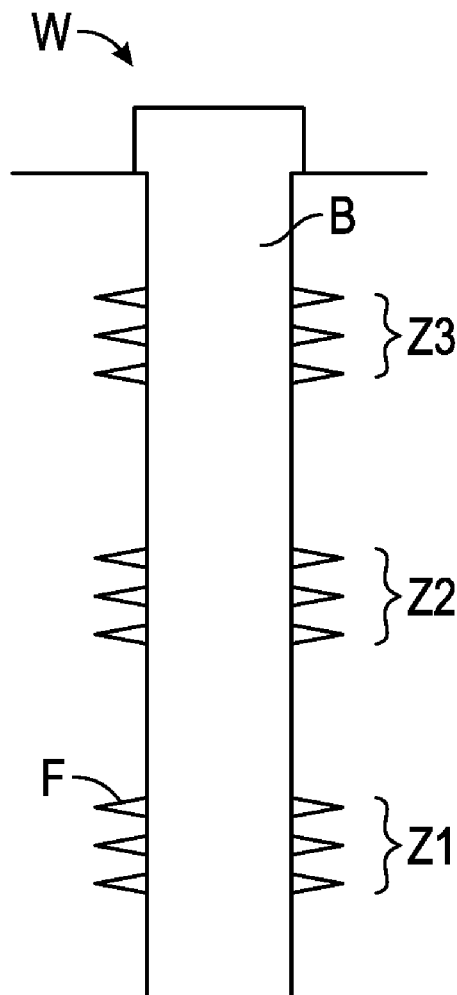




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(19) **United States**(12) **Patent Application Publication****Bogdan et al.**(10) **Pub. No.: US 2017/0138182 A1**(43) **Pub. Date: May 18, 2017**(54) **MOVING SYSTEM AND METHOD**(71) Applicant: **SCHLUMBERGER TECHNOLOGY CORPORATION**, Sugar Land, TX (US)(72) Inventors: **Andrey Bogdan**, Sugar Land, TX (US);
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Bruno Lecerf, Houston, TX (US)(21) Appl. No.: **14/939,803**(22) Filed: **Nov. 12, 2015****Publication Classification**(51) **Int. Cl.**
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(2013.01); **E21B 43/26** (2013.01)(57) **ABSTRACT**

A method to locate fracture zones in a well by emitting tube waves from different emission locations, sensing responses from the fracture zones at different corresponding receiving locations, and analyzing the responses to map the location of the fracture zones. Also, a system to locate the fracture zones in a well with an emitter movable to emit tube waves at different emission locations in the well, a downhole receiver adapted to sense responses at respective receiving locations a fixed distance relative to the emission locations, and a recorder to track the time between the emission and the response for the different emission locations. Also a downhole tool equipped with a tube wave emitter, a tube wave response receiver in a tandem arrangement with the emitter, and a deployment system selected from wireline, coiled tubing, tractor, and combinations thereof to move the emitter and receiver together in tandem.



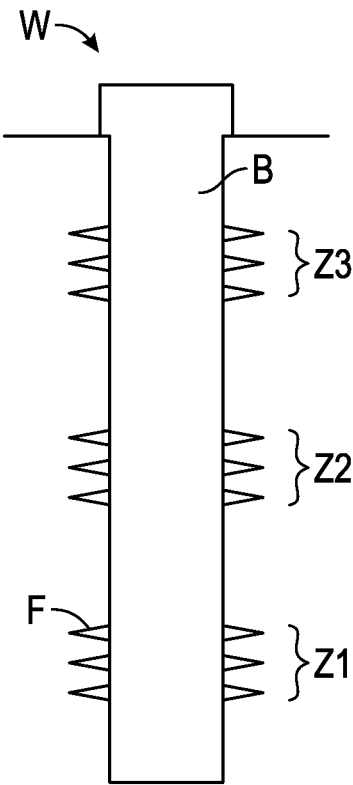


FIG. 1

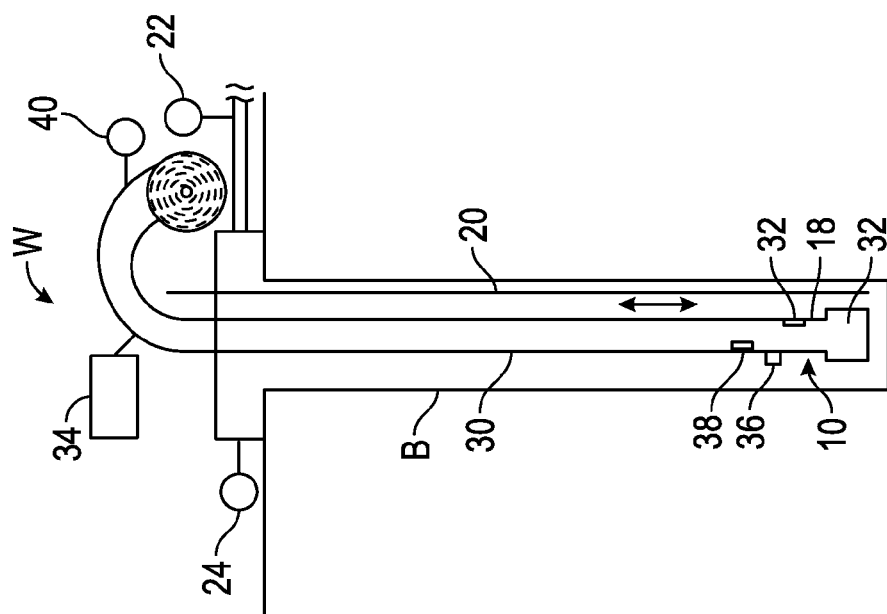


FIG. 2B

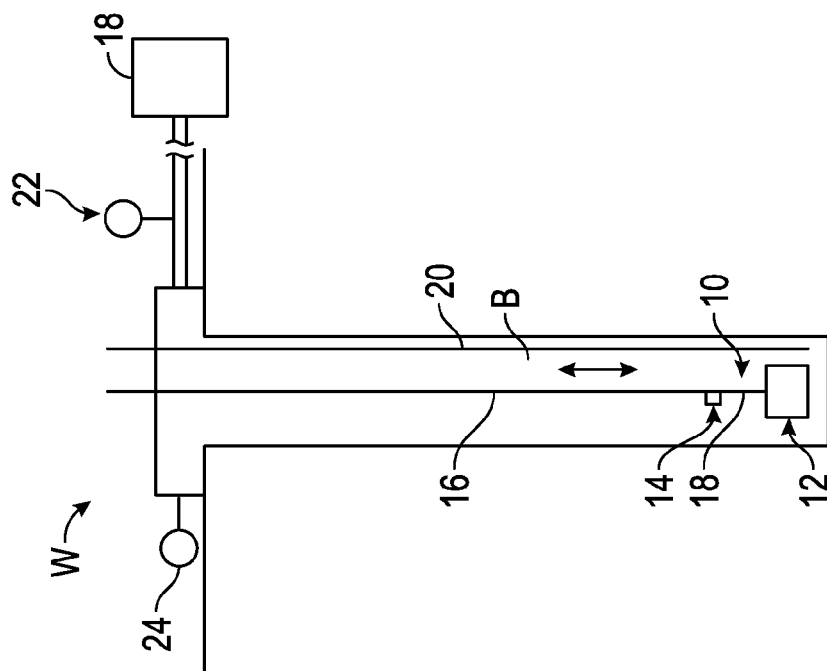


FIG. 2A

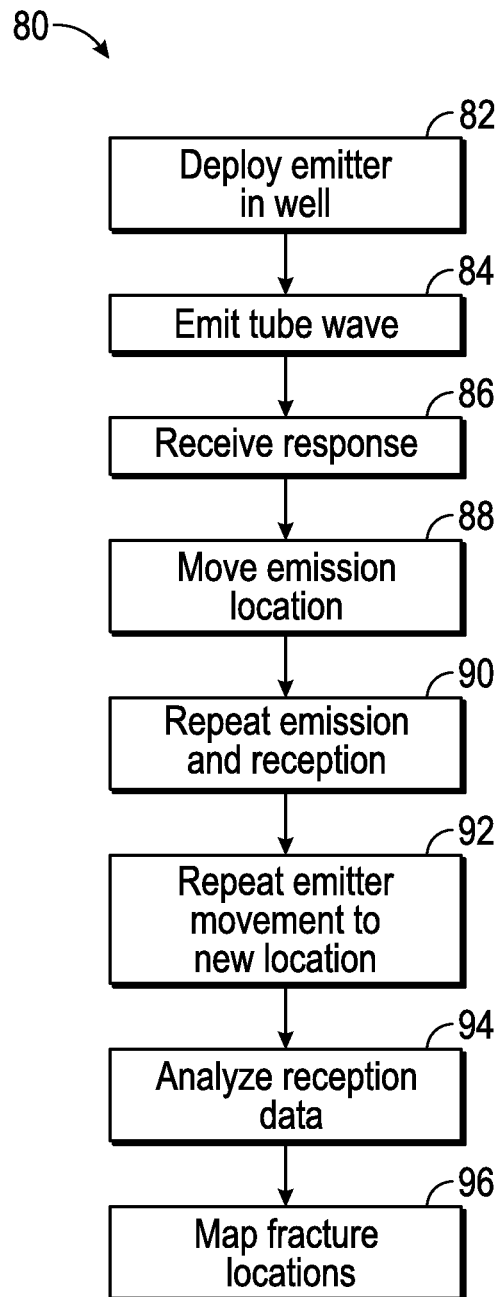


FIG. 3

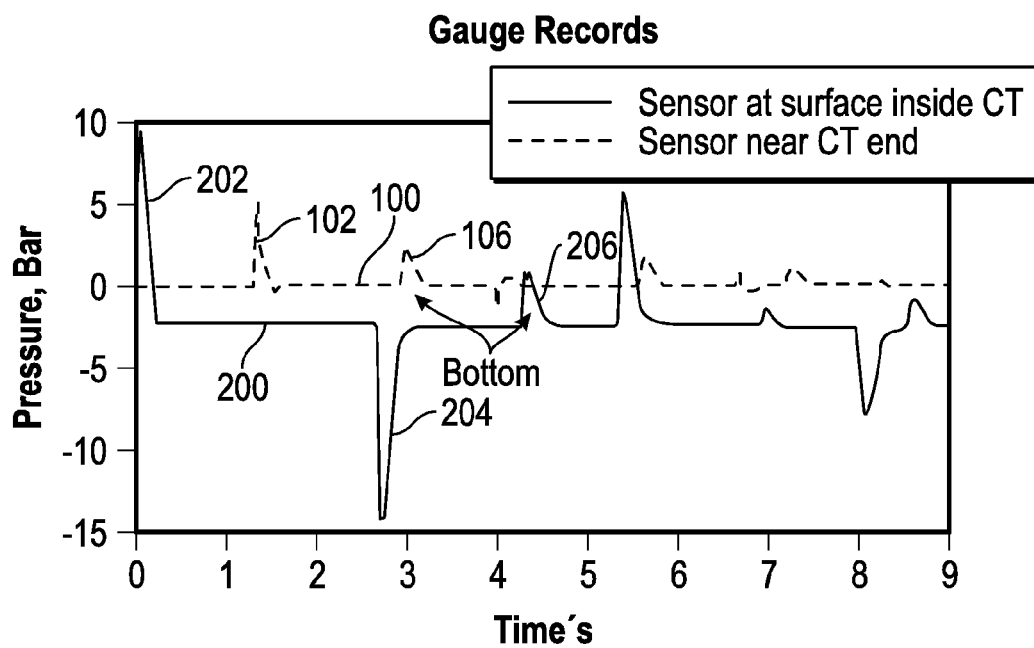


Fig. 4

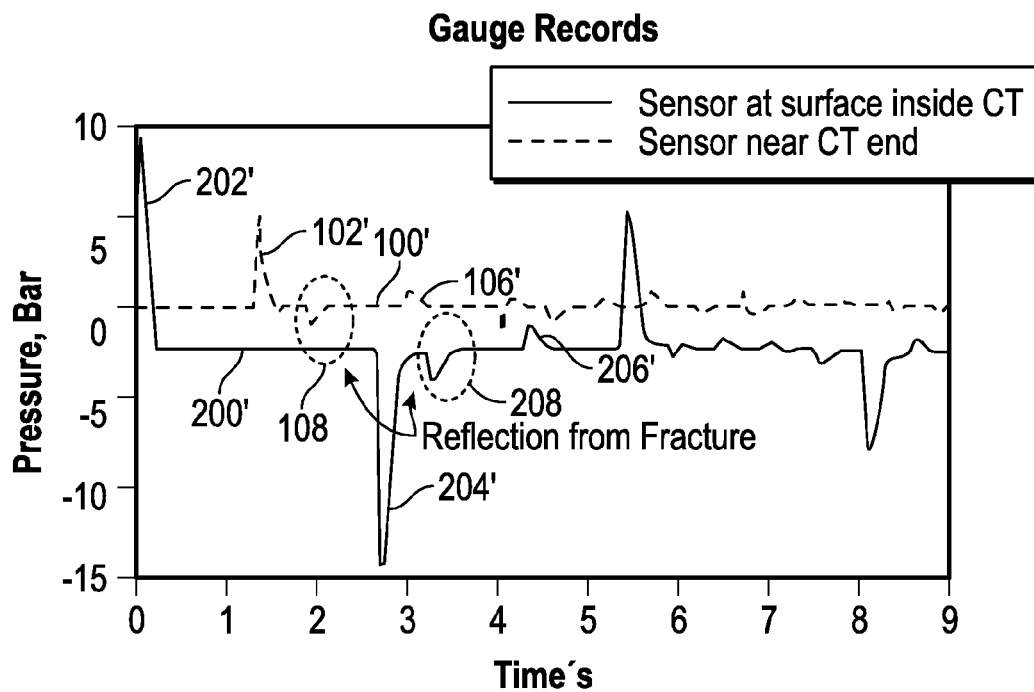


Fig. 5

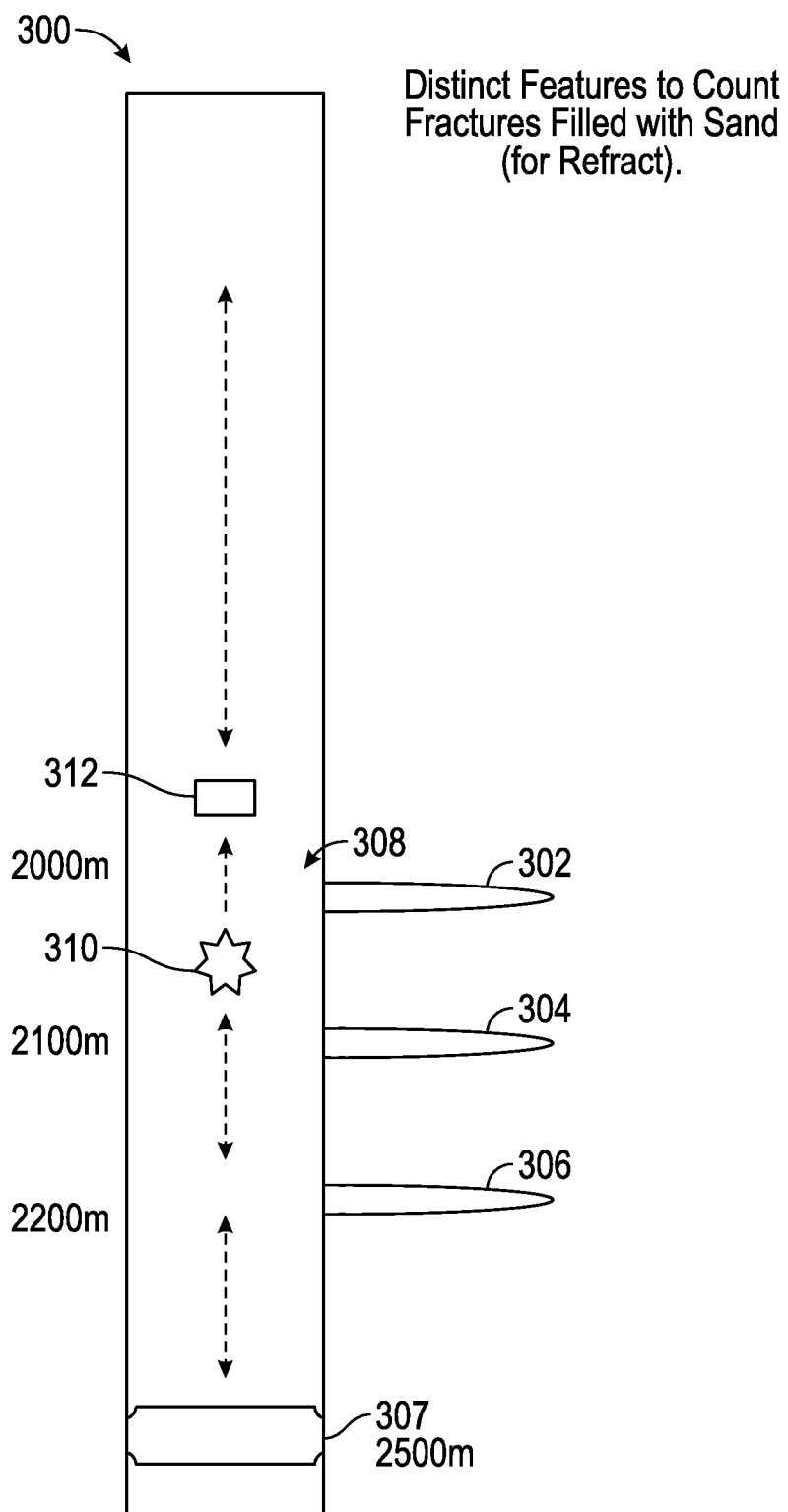
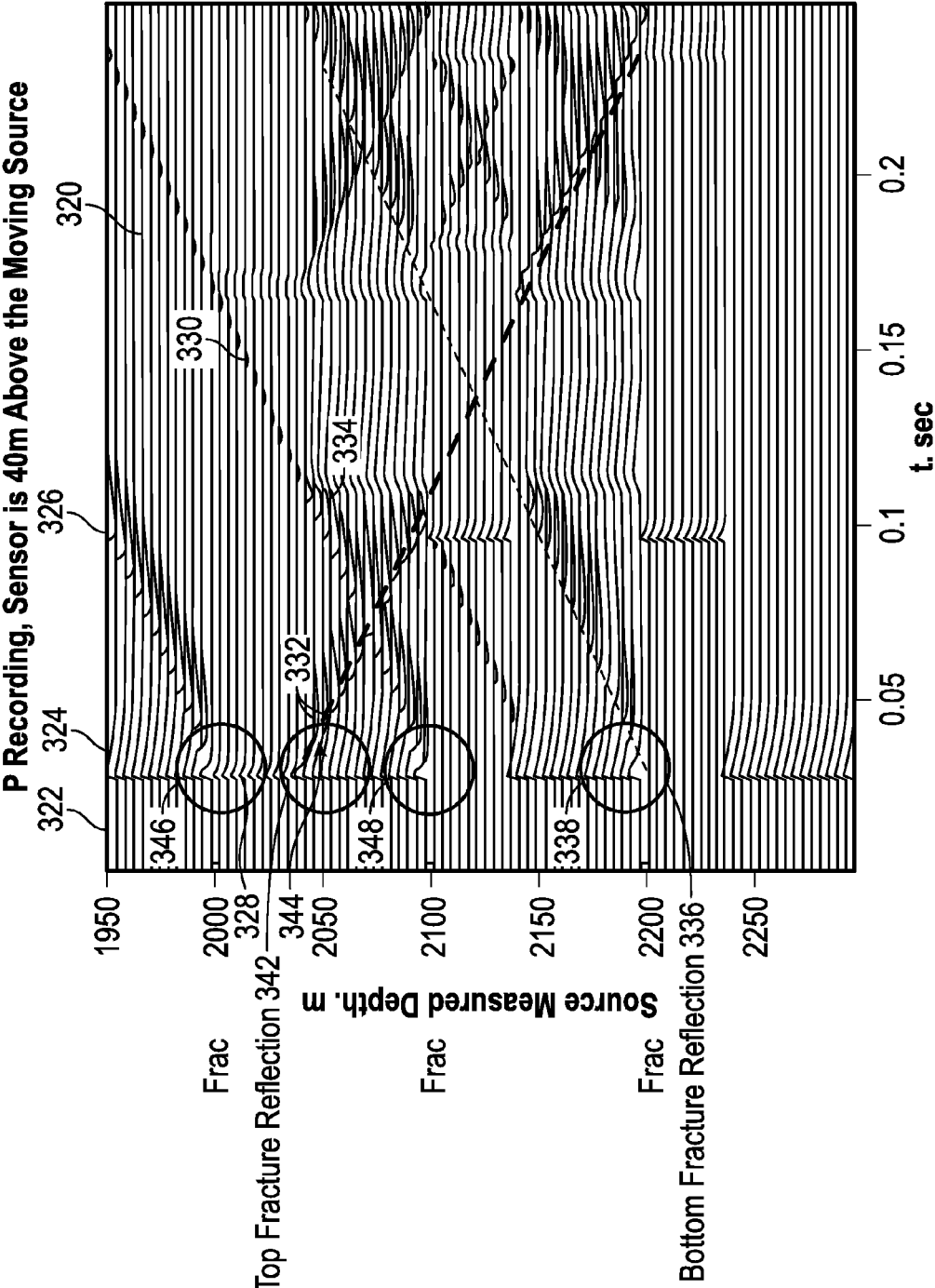


FIG. 6A



MOVING SYSTEM AND METHOD**CROSS REFERENCE TO RELATED APPLICATION(S)**

[0001] None.

BACKGROUND

[0002] The analysis of reflected pressure or tube waves has been used to detect a fracture or bottom irregularity in a well. Several references describe ways to analyze tube wave reflections, such as US 2011/0267922, US 2012/0018150, U.S. 61/923,216, and U.S. Pat. No. 7,819,188.

[0003] The industry has an ongoing requirements for the development or improvement of methods, systems, and tools to determine the location and/or status of fracture zones before, during, and/or after fracturing or refracturing operations, and or such methods, systems, and tools useful in wells with or expected to have multiple open fracture zones.

SUMMARY OF DISCLOSURE

[0004] In one aspect, embodiments of the present disclosure relate to methods, systems, and tools for the location of fracture zones in a well using tube waves, which are also referred to herein as pressure waves, emitted from different emission locations, such as by moving or as if by moving an emitter in the well, and sensing responses from the fracture zone(s) at different corresponding receiving locations, e.g., the receiving locations at a fixed distance from the emission locations such as by moving or as if by moving the receiver in tandem with the emitter and/or by using a moving emitter with a distributed sensor cable.

[0005] In some embodiments of this disclosure, a method to locate one or more fracture zones in a well comprises emitting a plurality of tube waves in the well from a like plurality of different emission locations; sensing for respective responses to the tube waves from each of the one or more fracture zones at a like plurality of different receiving locations; and analyzing the sensed responses at the different receiving locations to map the location of each of the one or more fracture zones. In some embodiments, the emitter is moved to the different locations. In some embodiments, each of the different receiving locations is a fixed distance from the respective emission locations.

[0006] In some embodiments of this disclosure, a downhole tool for mapping fracture zones in a well comprises a downhole assembly comprising: an emitter to emit tube waves, a receiver to sense responses to the tube waves characteristic of fracture zones, and an elongated member carrying the emitter and the receiver in tandem at a fixed relative spacing; and a deployment system selected from wireline, coiled tubing, a tractor, and combinations thereof to move the downhole assembly to different depths in the well.

[0007] In some embodiments of this disclosure, a system to locate one or more fracture zones in a well comprises an emitter movable in the well to emit tube waves at different emission locations in the well; a downhole receiver adapted to sense respective responses to the tube waves at respective receiving locations a fixed distance relative to the emission locations; and a recorder to track the time period between the emission of the tube waves and the sensed response for the different emission locations.

[0008] Other aspects and advantages of the disclosure will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0009] FIG. 1 is a schematic diagram of a well with multiple fracture zones of unknown location or status contemplated in some embodiments of the present disclosure.

[0010] FIG. 2A is a schematic diagram of a wireline fracture detection system, in accordance with embodiments of the present disclosure.

[0011] FIG. 2B is a schematic diagram of a coiled tubing fracture detection system, in accordance with other embodiments of the present disclosure.

[0012] FIG. 3 is a process flow diagram illustrating the steps or operations in a method according to some embodiments of the disclosure.

[0013] FIG. 4 is a pressure wave trace diagram from downhole sensors in a well showing reflections from a fracture in accordance with some embodiments of the disclosure.

[0014] FIG. 5 is a pressure wave trace diagram from the downhole sensors of FIG. 3 in the same well showing the absence of reflections from a fracture in accordance with some embodiments of the disclosure.

[0015] FIG. 6A is a schematic diagram showing features of a well and fracture detection system in which fractures are mapped in an example below in accordance with some embodiments of the disclosure.

[0016] FIG. 6B is a collection of pressure wave traces expected for the well of the FIG. 6A example in accordance with some embodiments of the disclosure.

DEFINITIONS

[0017] “Above”, “upper”, “heel” and like terms in reference to a well, wellbore, tool, formation, refer to the relative direction or location near or going toward or on the surface side of the device, item, flow or other reference point, whereas “below”, “lower”, “toe” and like terms, refer to the relative direction or location near or going toward or on the bottom hole side of the device, item, flow or other reference point, regardless of the actual physical orientation of the well or wellbore, e.g., in vertical, horizontal, downwardly and/or upwardly sloped sections thereof.

[0018] Adapted to—made suitable for a use or purpose; modified.

[0019] Analyze—to study closely and carefully.

[0020] Borehole or wellbore—the portion of the well extending from the Earth’s surface formed by or as if by drilling, i.e., the wellbore itself, including the cased and openhole or uncased portions of the well.

[0021] Carrying—adapted to move while supporting.

[0022] Casing/casing string—Large-diameter pipe lowered into an open hole and cemented in place.

[0023] Cluster—a collection of data points with similar characteristics.

[0024] Coiled tubing—a well operation or system employing a long continuous length of pipe wound and unwound from a spool to lower and raise downhole tools; the continuous length of pipe used in such operations.

[0025] Confirm—to make sure or demonstrate that something is true, accurate, or justified; verify; substantiate.

[0026] Deconvoluting—algorithmic processing to reverse the effects of convolution on recorded data.

[0027] Degradable—a material capable of breaking down, or chemically deteriorating, or changing state as by dissolution, sublimation or melting.

[0028] Degradation conditions—conditions at which the process of degrading a degradable material can initiate or continue.

[0029] As used herein, a degradable diverter placed in a flow passage has “substantially degraded” when the process of degrading has progressed to the point where fluid can readily pass through the flow path.

[0030] Depth—includes horizontal/lateral distance/displacement.

[0031] Derived (data)—obtained from a specified source. For the avoidance of doubt, data derived from a specified source may comprise or consist of the original data per se.

[0032] Determine—to establish or ascertain definitely, as after consideration, investigation, or calculation.

[0033] Diversion—the act of causing something to turn or flow in a different direction.

[0034] Diversion material—a substance or agent used to achieve diversion during stimulation or similar injection treatment; a chemical diverter.

[0035] Diversion pill—a relatively small quantity of a special treatment fluid blend used to direct or divert the flow of a treatment fluid.

[0036] Divert—to cause something to turn or flow in a different direction.

[0037] Diverter—anything used in a well to cause something to turn or flow in a different direction, e.g., a diversion material or mechanical device; a solid or fluid that may plug or fill, either partially or fully, a portion of a subterranean formation.

[0038] Each—used to refer to every one of two or more things, regarded and identified separately.

[0039] Embodiments—non-limiting tangible or visible forms of an idea or quality according to the present disclosure or invention.

[0040] “Emission location” as used herein refers to the point of origin or entry of a wave into the fluid in the main wellbore passage or annulus interfacing the casing or interior surface of the wellbore in an open completion, e.g., the transducer of a downhole emitter locally coupled to the wellbore fluid, the end or other opening of a coiled tubing that conducts a pressure wave via a fluid filling the coiled tubing from a remote pressure wave generator, etc. For purposes of the present disclosure and claims, an emitter is deemed to be in the well at the emission location even if the tube wave generation originates from a device located wholly or partially outside the wellbore.

[0041] Emit—to send out from a source.

[0042] Emitter—a device that emits something.

[0043] Fixed—predetermined and not subject to change.

[0044] Flow path—a passageway, conduit, porous material or the like through which fluid may pass.

[0045] Fluid communication—connection via a flow path.

[0046] Fluid hammer—a pressure surge or wave caused when a fluid in motion is suddenly forced to stop or change direction.

[0047] Formation—a body of rock that is sufficiently distinctive and continuous that it can be mapped, or more generally, the rock around a borehole.

[0048] Fracture—a crack or surface of breakage within rock.

[0049] Fracture zone—an interval having one or more fractures treated concurrently, e.g., fractures associated with a perforation cluster and/or treated in the same stage.

[0050] Hydraulic fracturing or “fracturing”—a stimulation treatment involving pumping a treatment fluid at high pressure into a well to cause a fracture to open.

[0051] Initiate—to cause a process or action to begin.

[0052] Injection—pumping fluid through the wellbore into the reservoir for storage or to maintain pressure and/or in a flooding operation.

[0053] Instantaneous shut-in pressure or ISIP—the shut-in pressure immediately following the cessation of the pumping of a fluid into a well.

[0054] Interval—a space between two points or times, e.g., the space between two points in a well.

[0055] Lateral—a branch of a well radiating from the main borehole.

[0056] Liner—a casing string that does not extend to the top of the wellbore, but instead is anchored or suspended from inside the bottom of the previous casing string.

[0057] Map—make a diagrammatic representation of an area or region indicating physical features.

[0058] Measure—to ascertain the value, number, quantity, extent, size, amount, degree, or other property of something by using an instrument or device.

[0059] Modify—to make partial or minor changes to (something), typically so as to improve it or to make it less extreme.

[0060] Monitor—to observe, record or detect the progress or quality of something over a period of time; keep under systematic review for purposes of control or surveillance.

[0061] Overlapping—partly coinciding in time or spatial dimension(s).

[0062] Perforation—the communication tunnel created from the casing or liner into the reservoir formation, through which fluids may flow, e.g., for stimulation and/or oil or gas production.

[0063] Perforation cluster—a group of nearby perforations having similar characteristics.

[0064] Pill—any relatively small quantity of a special blend of drilling or treatment fluid to accomplish a specific task that the regular drilling or treatment fluid cannot perform.

[0065] Pressure signal emitter—a non-pumping device specially adapted to form a pressure wave in a wellbore, usually in communication with the high pressure side (outlet or discharge) of a fluid pump.

[0066] Progression—a movement or development toward a destination or a more advanced state, especially gradually or in stages; a succession; a series.

[0067] Proppant—particles mixed with treatment fluid to hold fractures open after a hydraulic fracturing treatment.

[0068] Proppant pumping schedule—a pumping sequence comprising the volume, rate, and composition and concentration of a proppant-laden fluid, and any associated treatment fluids such as an optional pad, optional spacers, and an optional flush.

[0069] Receive—to convert a signal to a file, sound, visual display or other perceptible medium.

[0070] Receiver—an electrical or computer apparatus that converts a signal to a file, sound, visual display or other perceptible medium.

[0071] “Receiving location” as used herein refers to the point in the wellbore fluid from whence the signal is received, e.g., at the transducer of a downhole receiver where it is coupled to the wellbore fluid. For purposes herein a distributed sensor cable is considered to provide a receiving location at all points along the extent of the cable capable of sensing a signal.

[0072] Refracturing or refrac—fracturing a portion of a previously fractured well after an initial period of production. The fractures from the earlier treatment are called “pre-existing fractures”.

[0073] Regularly changing frequency—a frequency (cycles per time) that varies in an ordered pattern.

[0074] Remote—distant or far away.

[0075] Reservoir—a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids.

[0076] Respective—belonging or relating separately to each of two or more things.

[0077] Response—the reaction resulting from a stimulus.

[0078] Re-stimulation—stimulation treatment of any portion of a well, including any lateral, which has previously been stimulated.

[0079] Revise—alter in light of developments.

[0080] Sending—cause (a message or computer file) to be transmitted electronically.

[0081] Sensing—automatically detecting or measuring something.

[0082] Sensor—a device that detects or measures a physical property and records, indicates or otherwise responds to it.

[0083] Shut in—closing a wellbore at the surface, e.g., at or near the Christmas tree, blowout preventer stack

[0084] Shut-in pressure or SIP—the surface force per unit area exerted at the top of a wellbore when it is closed, e.g., at the Christmas tree or BOP stack.

[0085] Simulate—to create a representation or model of something, e.g., a physical system or particular situation.

[0086] Stage—a pumping sequence comprising a proppant pumping schedule and a diversion pill pumping schedule, including pads, spacers, flushes and associated treatment fluids.

[0087] Stimulation—treatment of a well to enhance production of oil or gas, e.g., fracturing, acidizing, and so on.

[0088] Surface—the surface of the Earth.

[0089] Sweep circuit—an electronic or mechanical device which creates a waveform with a regularly changing frequency or amplitude, usually a linearly varying frequency and a constant amplitude.

[0090] Tandem—having two things arranged one in front of the other.

[0091] Tractor—a powered vehicle with wheels or treads used to haul or move equipment.

[0092] Treatment—the act of applying a process or substance to something to give it particular properties.

[0093] Treatment fluid—a fluid designed and prepared to resolve a specific wellbore or reservoir condition.

[0094] Tube wave—a periodic pressure disturbance in which alternating compression and rarefaction are propagated through or on the surface of a medium without translation of the material; also known as a pressure wave or Stoneley wave.

[0095] Well—a deep hole or shaft sunk into the earth, e.g., to obtain water, oil, gas, or brine.

[0096] Wireline—a well operation or system employing single-strand or multi-strand wire or cable to lower and raise downhole tools; the wire or cable used in such operations.

DETAILED DESCRIPTION

[0097] In the following description, numerous details are set forth to provide an understanding of the present disclosure. However, it may be understood by those skilled in the art that the methods of the present disclosure may be practiced without these details and that numerous variations or modifications from the described embodiments may be possible. At the outset, it should be noted that in the development of any such actual embodiment, numerous implementation—specific decisions may be made to achieve the developer’s specific goals, such as compliance with system related and business related constraints, which will vary from one implementation to another. 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 this disclosure. In the summary and this detailed description, each numerical value should be read once as modified by the term “about” (unless already expressly so modified), and then read again as not so modified unless otherwise indicated in context. Also, in the summary and this detailed description, it should be understood that a range listed or described as being useful, suitable, or the like, is intended to include support for any conceivable sub-range within the range at least because every point within the range, including the end points, is to be considered as having been stated. For example, “a range of from 1 to 10” is to be read as indicating each possible number along the continuum between about 1 and about 10. Furthermore, one or more of the data points in the present examples may be combined together, or may be combined with one of the data points in the specification to create a range, and thus include each possible value or number within this range. Thus, (1) even if numerous specific data points within the range are explicitly identified, (2) even if reference is made to a few specific data points within the range, or (3) even when no data points within the range are explicitly identified, it is to be understood (i) that the inventors appreciate and understand that any conceivable data point within the range is to be considered to have been specified, and (ii) that the inventors possessed knowledge of the entire range, each conceivable sub-range within the range, and each conceivable point within the range. Furthermore, the subject matter of this application illustratively disclosed herein suitably may be practiced in the absence of any element(s) that are not specifically disclosed herein.

[0098] Some embodiments of the present disclosure relate to methods, systems, and tools to identify open fracture zones in a well and determine the location at which they intercept the wellbore, before, during, and/or after a well treatment, e.g., a well stimulation operation such as a fracturing or refracturing treatment. In some embodiments, tube waves are emitted from different emission locations by moving or as if by moving an emitter in the well, and sensing responses from the fracture zone(s) at corresponding receiving locations having a fixed relationship to the respective emission location. When a tube wave reflects from an interface or change in the tubular media such as a fracture zone, the response is a reflection related to the original wave, but modified by the character of the reflector. In some

embodiments, the emitter is moved to different locations in the wellbore, and a receiver is coupled to the emitter at a fixed spacing so that the emitter and receiver are moved together in tandem, and/or a distributed receiver such as a fiber optic sensor cable is deployed in the wellbore. For the purposes of the present disclosure and claims, the location of the emitter is considered to be the location in the main wellbore passage or annulus where the pressure signal originates, e.g., at the bottom end of a coiled tubing where the wave is conducted from a pressure wave generated in communication with the coiled tubing from a remote location such as the surface, travels down the coiled tubing, and enters the wellbore annulus at the lower end or other opening of the coiled tubing to the annulus.

[0099] In some embodiments, a method to locate one or more fracture zones in a well comprises: (a) emitting a plurality of tube waves from an emitter in the well from a like plurality of different emission locations; (b) sensing for respective responses to the tube waves from the one or more fracture zones at a like plurality of different receiving locations; and (c) analyzing the sensed responses at the different receiving locations to map the location of the one or more fracture zones.

[0100] In some embodiments, the method further comprises moving the emitter to the different emission locations. In some embodiments, the different receiving locations are a fixed distance from the respective emission locations. In some embodiments, the method further comprises deploying a distributed sensor in the well to sense the emissions and responses.

[0101] In some embodiments, the method comprises moving an emitter-receiver tool in the well, the tool comprising the emitter and a receiver arranged in tandem or otherwise with the receiver positioned at a fixed distance relative to the emitter, and in some embodiments further comprises deploying a distributed sensor in the well to sense the emissions and responses. In some embodiments, the method comprises moving the emitter at a constant rate in the well, emitting the tube waves at evenly spaced time intervals, or a combination thereof.

[0102] In some embodiments, the plurality of emission locations comprise a first set of the emission locations above a first fracture zone and a second set of the emission locations below the first fracture zone. In some of these embodiments, for example, the emitter is moved in the wellbore across the first fracture zone. In some embodiments, the first set of emission locations is located intermediate the first fracture and an adjacent higher fracture, the second set of emission locations is located intermediate the first fracture and an adjacent lower fracture, or both of the first and second sets of emission locations are located intermediate respective adjacent higher and lower fractures. In some of these embodiments, for example, the wellbore comprises multiple fracture zones and emitter is moved in the wellbore across the first fracture zone, and or across an adjacent fracture zone.

[0103] In some embodiments, the plurality of receiving locations comprise a first set of the receiving locations above a first fracture and a second set of the receiving locations below the first fracture. In some of these embodiments, for example, the receiver is moved in the wellbore across the first fracture zone and/or a distributed sensor cable is positioned across the first fracture zone. In some embodiments, the first set of receiving locations is located intermediate the

first fracture and an adjacent higher fracture, the second set of receiving locations is located intermediate the first fracture and an adjacent lower fracture, or both of the first and second sets of receiving locations are located intermediate respective adjacent higher and lower fractures. In some of these embodiments, for example, the wellbore comprises multiple fracture zones and the receiver is moved in the wellbore across the first fracture zone, and or across an adjacent fracture zone; and/or the wellbore comprises multiple fracture zones and a distributed sensor cable is positioned across the first fracture zone and or across an adjacent fracture zone.

[0104] In some embodiments, the method further comprises sensing the emissions and/or responses at a surface receiver. In some embodiments, the method further comprises deploying the emitter on a wireline, coiled tubing, tractor, or a combination thereof.

[0105] In some embodiments, the method further comprises planning a treatment of the well based on the mapped fracture locations, and or implementing the treatment in accordance with the plan.

[0106] In some embodiments according to the present disclosure, a downhole tool for mapping fracture zones in a well comprises: (a) a downhole assembly comprising: (i) an emitter to emit tube waves; (ii) a receiver to sense responses to the tube waves characteristic of fracture zones; and (iii) an elongated member carrying the emitter and the receiver in a tandem arrangement with a fixed relative spacing; and (b) a deployment system to move the downhole assembly to different depths, selected from wireline, coiled tubing, a tractor, and combinations thereof.

[0107] In some embodiments according to the present disclosure, a system to locate one or more fracture zones in a well, comprises: (a) an emitter movable in the well to emit tube waves at different emission locations in the well; (b) a downhole receiver adapted to sense respective responses to the tube waves at respective receiving locations a fixed distance relative to the emission locations; and (c) a recorder to track the time period between the emission of the tube waves and the sensed response for the different emission locations.

[0108] In some embodiments, the system further comprises a wireline, coiled tubing, or tractor carrying the emitter for deployment. In some embodiments, the downhole receiver is carried on the wireline, coiled tubing, or tractor in tandem with and at a fixed distance relative to the emitter. In some embodiments, the emitter is connected to a free end of the coiled tubing and the downhole receiver is mounted inside the coiled tubing, outside the coiled tubing, or a combination thereof. In some embodiments, the system further comprises a distributed sensor in the well.

[0109] In some embodiments of the system, the downhole receiver comprises a distributed sensor. In some embodiments, the system further comprises a surface receiver adapted to sense the tube wave emissions, the responses to the tube waves, or a combination thereof.

[0110] In some embodiments, the system further comprises a controller to deploy the emitter to different depths in the well. In some embodiments, the controller is adapted to deploy the emitter at a constant rate of travel and release a continuous tube wave emission from the emitter. In some embodiments, the controller is adapted to release a tube wave emission from the emitter at spaced intervals.

[0111] According to some embodiments herein, the tube waves reflected to the sensor location are from an open fracture, or a wellbore plug such as a ball or bridge plug. The reflection from a wellbore plug, normally having the same sign as the interrogating signal, implies that the sealing ball is properly placed and/or did not degrade. In some embodiments, degradation of a degradable diverter used to plug a fluid flow path, within the wellbore, e.g., a bridge plug, or connected to the wellbore, e.g., a fracture, and degradation is monitored using the reflection of the tube waves. The change or disappearance of reflections from the wellbore plug indicates degradation of the plug and lost sealing of the zone and/or readiness for production or injection.

[0112] In some embodiments, a sealed fracture which is not open to the well and/or in which a diverter has been placed produces no reflection, or a small or undetectable reflection, but appearance of a reflection from the perforation interval, typically with a negative sign compared to the interrogating signal, can indicate the presence, establishment or restoration of a hydraulic connection between the wellbore and the fracture zone, i.e., it is readied for injection or production as the case may be.

[0113] Two extreme types of tube wave reflection are thus of particular interest in some embodiments: those of a closed end wellbore, and those of an open end. A closed end is one in which there is little or no compliance at the reflector; a capped pipe is an example of this. An open end is one in which there is a large compliance at the reflector; a pipe ending in a large tank is an example of this. Such compliance can consist of a significant sealed volume of fluid, a free surface, or a connection to a reservoir, such as a hydrocarbon reservoir. The fluid flow characteristics of the connection between the two affect the magnitude of the reflection; a free flowing connection, i.e., an open end, produces the largest reflection; a non-flowing connection, i.e., a closed end, similarly produces a large reflection; and a connection with significant flow resistance produces a smaller reflection. At some point as the flow blockage is gradually removed, the impedance or resistance of the connection approximates the characteristic impedance of the pressure wave media, i.e., the wellbore, casing or other material having a surface interfacing the fluid filling the wellbore. At this point all of the incoming energy may be absorbed by the resistance of the connection, leading to no reflection at all, and this non-reflecting end is referred to as a terminator.

[0114] In some embodiments of the present disclosure, the emitter and/or receiver locations include those located on either side of one or more fracture zones, and/or between adjacent ones of the fracture zones in the case of multiple fracture zones in the well. With reference to FIG. 1, there is shown an exemplary well to be mapped after or during a fracture treatment, or before, during or after a refracturing treatment, in some embodiments comprises multiple fracture zones Z1, Z2, Z3 comprising one or more fractures F at various intervals along the wellbore B. In this example, the fractures F in fracture zones Z1, Z3 are open in fluid communication with the wellbore B, and are capable of producing tube wave reflections, whereas fracture zone Z2 has closed or blocked fractures that do not communicate with the wellbore, from which there is no response to tube waves. This closed fracture zone Z2 can be a common occurrence in refracturing operations or shift in a well where a diverter fluid is used.

[0115] With reference to the embodiments illustrated in FIG. 2A, in which like reference numerals and letters indicate like parts, a movable downhole emitter-receiver assembly 10 has a tube wave emitter 12 and a receiver 14 connected to wireline 16. Movement of the assembly 10 up or down in the wellbore B obtains a tandem movement of the emitter 12 and receiver 14, which are maintained in spaced relationship by the tensioned connecting section 18 of the wireline 16.

[0116] The emitter 12 can be any pressure wave generating source that emits a tube wave, such as a fluid pulsing source or pump. An optional alternative or additional surface pressure wave signal source (not shown) may be included in some embodiments, such as a pulsing source, and/or a treatment fluid pump used to generate a pressure wave by a sharp stop of the pump, which is propagated downhole. The receiver 14 in some embodiments detects the tube wave signal directly if there are no open fractures between the emitter 12 and the receiver, or the remaining signal wave passing an intervening fracture, and also receives the reflections from the tube wave from adjacent fractures above and/or below the emitter 12 and/or receiver 14.

[0117] The tube wave reflections are formed, for example, by any open fracture zones such as Z1, Z3 (see FIG. 1), whereas the reflection from closed or poorly communicating fractures such as Z2 is weak if present at all, and may not be detected. Since the receiver 14 moves in tandem with the emitter 12 in these embodiments, the receiver 14 is thus always the same distance from the emitter 12, and the distance of the receiver 14 relative to an adjacent fracture zone is proportional to the time it takes for the reflection to be sensed. As the assembly 10 is moved relative to the open fracture zone, the time between tube waves emitted at different locations will decrease as the receiver 14 approaches the fracture zone or increase as it moves away.

[0118] The location of a fracture zone can thus be determined by plotting the time to receiving the response versus the depth of the emitter 12 and/or receiver 14. For example, as the assembly 10 is moved down the wellbore B to approach an open fracture zone, the time to sense the reflection at the receiver 14 from the fracture below decreases until it reaches the fracture where dt is zero. As the emitter 12 passes below the fracture, no signal may be received from the fracture now between the emitter 12 and the receiver 14, until the receiver 14 also passes below the fracture; and then as the assembly 10 is lowered below the fracture, the reflection from the fracture now above the receiver 14 is seen again and the time increases as the assembly is lowered further into the borehole B. In this example, the depth of the fracture is determined as the intercept of the time of the reflection (at time=dt) plotted against the depth of emitter 12 during the initial approach on lowering, and/or the intercept of the time of the reflection (at time=dt) plotted against the depth of receiver 14 as the assembly 10 is continued to be lowered below the fracture, or vice versa on raising the assembly 10 from below a fracture.

[0119] In some embodiments, the system of FIG. 2A can include a distributed sensor 20, such as a fiber optic cable, for example, and can optionally be used in lieu of the wireline receiver 14 to replace it, or in addition to the wireline receiver 14, to track the tube wave emissions and/or reflections along the wellbore B. Additionally, in any embodiments herein either or both of an optional pressure

signal source **22** such as a pulsing source or treatment pump, and/or optional sensor **24**, are located in a fixed position or depth, e.g., on the surface, and hydraulically or fluidly connected to wellbore B. In any embodiments herein, optional receivers such as the distributed sensor cable **20** and/or surface sensor **24** provide additional ways to measure the emitted and/or reflected signal, for example, to confirm or verify readings from the wireline receiver **14** and/or as a backup in the event of signal loss from the wireline receiver **14**.

[0120] In the embodiments illustrated in FIG. 2B, wherein like reference numerals and letters indicate like parts and features, are similar to FIG. 2A except that a coiled tubing **30** is used, which may optionally be in addition to the wireline **16** (see FIG. 2A).

[0121] In these embodiments, the emitter **32** may simply be an open end of the coiled tubing **30** connected to a remote tube wave generator **34** hydraulically connected to coiled tubing **30** on the surface or another location to generate the pressure signal source, e.g., a pulsing and/or sweeping source, or fluid hammer generated by a pump; or the emitter **32** can be engaged by fluid flow through the coiled tubing **30** to generate a pressure signal as a sweeping source, such as a sweeping source generated by a seismic truck using sine waves of varying frequency described for example in U.S. Pat. No. 7,050,356, U.S. Pat. No. 7,515,505, U.S. Pat. No. 4,823,326 or using mud pulse telemetry, such as the pressure pulse generator described in U.S. Pat. No. 6,970,398, incorporated herein by reference, or the pressure pulse generator and/or the communication system or method described in U.S. Pat. No. 7,552,761, incorporated herein by reference, or the like.

[0122] In some embodiments, a receiver **36** can be located in the wellbore-coiled tubing annulus, e.g., mounted on an exterior surface of the tubing **30**, and/or receiver **38** within the tubing, e.g., mounted on an interior surface of the tubing **30**, and/or receiver **40** located in a fixed position or depth, e.g., on the surface, and hydraulically or fluidly connected to coiled tubing **30**. If desired, the coiled tubing **30** can incorporate the fiber optics system and methods for coiled tubing described in U.S. Pat. No. 7,617,873, incorporated herein by reference, in addition to or in lieu of distributed sensor cable **20** or any of receivers **36**, **38**, **40**.

[0123] In embodiments a tractor can be used to deploy the emitters **12** and **32** and or receivers **14** and **36**. The tractor in some embodiments may optionally be in addition to the wireline **16** (see FIG. 2A) and/or the coiled tubing **30** (see FIG. 2B). In some embodiments, the receivers **14** and **36** are maintained in a tandem relationship with the emitters **12** and **32**, which are attached at either end of elongated members **18** and **30**. Additionally, the tractor enables the emitter and receivers to move throughout the casing in high friction areas such as a horizontal lateral or scaled casing that may be present in a refracturing well.

[0124] In some embodiments, any of the wireline, coiled tubing and/or tractor components or features can be used together or separately in any combination or subcombination for various operations, e.g., in perforating operations a wireline can deploy the emitter-receiver tool and a coiled tubing and/or tractor can convey the perforating gun. Further, the embodiments shown in FIGS. 2A and/or 2B can be used together in combination or subcombination or in duplication, e.g., the downhole emitter(s) can be deployed with one or more of the wireline, coiled tubing, and/or tractor

while the downhole receiver(s) can be deployed with another one or more of the wireline, coiled tubing, tractor, and/or distributed sensor cable. Further, in some embodiments, the wireline, coiled tubing, tractor, etc. used to deploy the emitter and/or receiver may also be used to deploy or operate other tools, sensors, materials, fluids, and so on.

[0125] In some embodiments, the generation of pressure waves from the emitter can take place in a set of spaced intervals planned in advance and/or determined or modified as the method progresses. For example, the emitter-receiver tool assembly **10** (see FIGS. 2A/B) can be moved and release a pressure signal at set depths, e.g., at an even spacing of 1 to 100 meters; or it can be moved at a set rate (m/s) and take readings at evenly spaced time intervals, e.g., every 0.5 second up to every several minutes; or it can be moved at a set rate (m/s) while releasing a continuous wave such as a sweep signal. In some embodiments, by pulsing at multiple locations the reflections from different fractures can be analyzed and imposed on each other to create a full map of a bottom hole assembly and existing fractures. This map can be used, for example, to plan the number of refracturing stages with diversion or/and the number and volume of diversion pills.

[0126] In some embodiments, any of the methods described herein can be used to confirm the location and/or status of multiple fracture zones in a well in conjunction with appropriate treatment methods, e.g., before, during, and/or following a fracturing or refracturing operation or following a period of production. For example, the method can be used:

[0127] a. to determine the status or location of multiple fracture zones in a well to forecast or modify production from the well, or to determine the suitability for and/or type of remedial treatment;

[0128] b. to determine the status and location of multiple fracture zones before initiating a refracturing treatment, e.g., to plan the number of stages and/or the size of diverter pills for the refracturing job;

[0129] c. to determine the status and location of fractures during a fracturing or refracturing job so that the completion of one stage can progress to the next, or so that the placement of diverters or bridge plugs can be confirmed or verified, and so on; and/or

[0130] d. to determine the status and location of fractures following a fracturing or refracturing job so that the effectiveness of the treatment and/or associated cleanup operation can be assessed, and/or so that the readiness of the well to be placed into production can be assessed, etc.

[0131] Some of the embodiments disclosed herein have potential application in a diversion operation in new fracturing treatments or in refracturing treatments, e.g., wherein diversion material is pumped to seal the hydraulic connections between the fractures and the wellbore before the next successive stimulation stage. For example, analysis of reflected waves coming from the depth of a particular fracture is used in some embodiments to monitor the degradation of the diverting material. At the end of a stimulation stage, before sealing, the fracture from the stage will produce reflection with strong amplitude. After sealing the fracture with diversion material the reflection from that interval will become weak or disappear. When the diversion

material degrades, there will again be a strong reflection from that depth, indicating that the fracture is ready for returning the well to service.

[0132] Monitoring of the degradation of the degradable diverters in some embodiments can be used to change one or more operating parameters of the well, e.g., in response to the changes in the observed reflections, proportional changes in the operation of the well can be instituted, in some embodiments automatically, or a decision to begin producing the well and/or the zones ready to be placed into production (or injection) can be made based on actual measured degradation, rather than an estimated time. This can be an advantage when downhole conditions are not precisely known and/or other factors make a precise determination of the degradation time otherwise unpredictable, and according to some embodiments herein the well can be placed into production earlier than the period estimated for complete degradation if this is the case, or production can be delayed until complete degradation is confirmed if it is not the case. For example, the time required for the degradation of diversion materials and/or wellbore plugs is sensitive to fluid salinity, pressure, and temperature, as well as the physical condition and quality of the diverter or plug itself, which may degrade differently under (generally unknown) downhole conditions, and the use of a laboratory master curve may not give a precise prediction of the kinetics of the process.

[0133] With reference to FIG. 3, a process flow diagram illustrates some of the steps, operations, events, tasks, or features for fracture analysis or determination of fracture locations according to the method 80. In operation 82, an emitter is deployed in a well such as a well having multiple fracture zones, e.g., with a wireline, coiled tubing, tractor, or the like. At a first location, a tube wave emission 84 is followed by response reception 86 for that location. The response can be received with a receiver deployed downhole with the emitter, e.g., in tandem, or with a distributed receiver such as a distributed sensor cable deployed in the well. Then in step 88 the emitter is moved to a different location in the well, and in step 90 the emission 84 and reception 84 are repeated at that location. Until the emissions 84 have been completed at each of the desired locations, operation 92 repeats steps 88 and 90. The locations in steps 82, 88, 92 can include depths above, below, and/or between one or more fractures in the well. Next, the data are analyzed in step 94, and the fracture locations are mapped in step 96. The analysis 94 and/or mapping 96 can be done after all the data are collected, or they can be performed in real time and updated with new data as the data points are collected.

EMBODIMENTS LISTING

[0134] In some aspects, the disclosure herein relates generally to well re-stimulation methods and/or workflow processes according to the following Embodiments, among others:

[0135] Embodiment 1: A downhole tool for mapping fracture zones in a well, comprising: (a) a downhole assembly comprising: (i) an emitter to emit tube waves; (ii) a receiver to sense responses to the tube waves characteristic of fracture zones; and (iii) an elongated member carrying the emitter and the receiver in a tandem arrangement with a fixed relative spacing; and (b) a deployment system to move

the downhole assembly to different depths selected from wireline, coiled tubing, tractor, and combinations thereof.

[0136] Embodiment 2: a system to locate one or more fracture zones in a well, comprising the tool of Embodiment 1 and a recorder to track the time period between the emission of the tube waves and the sensed response to the emission at different depths.

[0137] Embodiment 3: A system to locate one or more fracture zones in a well, comprising: (a) an emitter movable in the well to emit tube waves at different emission locations in the well; (b) a downhole receiver adapted to sense respective responses to the tube waves at respective receiving locations a fixed distance relative to the emission locations; and (c) a recorder to track the time period between the emission of the tube waves and the sensed response for the different emission locations.

[0138] Embodiment 4: The system of Embodiment 2 or Embodiment 3, wherein the downhole receiver comprises a distributed sensor.

[0139] Embodiment 5: The system of any one of Embodiments 2 to 4, comprising a wireline, or coiled tubing, or tractor, carrying the emitter for deployment.

[0140] Embodiment 6: The system of Embodiment 5, wherein the downhole receiver is carried on the wireline, or coiled tubing, or tractor, in a tandem arrangement at a fixed distance relative to the emitter.

[0141] Embodiment 7: The system of Embodiment 5 or Embodiment 6, wherein the emitter is connected to a free end of the coiled tubing and the downhole receiver is mounted inside the coiled tubing, outside the coiled tubing, or a combination thereof.

[0142] Embodiment 8: The system of any one of Embodiments 5 to 7, further comprising a distributed sensor in the well.

[0143] Embodiment 9: The system of any one of Embodiments 2 to 8, further comprising a surface receiver adapted to sense the tube wave emissions, the responses to the tube waves, or a combination thereof.

[0144] Embodiment 10: The system of any one of Embodiments 2 to 9, further comprising a controller to deploy the emitter to different depths in the well.

[0145] Embodiment 11: The system of Embodiment 10, wherein the controller is adapted to deploy the emitter at a constant rate of travel and release a continuous tube wave emission from the emitter.

[0146] Embodiment 12: The system of Embodiment 10 or Embodiment 11, wherein the controller is adapted to release a tube wave emission from the emitter at spaced intervals.

[0147] Embodiment 13: A method to locate one or more fracture zones in a well, comprising: using the system of any one of Embodiments 2 to 12 for (a) emitting a plurality of tube waves from a like plurality of different emission locations; (b) sensing for respective responses to the tube waves from the one or more fracture zones at a like plurality of different receiving locations; and (c) analyzing the sensed responses at the different receiving locations to map the location of the one or more fracture zones.

[0148] Embodiment 14: A method to locate one or more fracture zones in a well, comprising: (a) emitting a plurality of tube waves from an emitter in the well from a like plurality of different emission locations; (b) sensing for respective responses to the tube waves from the one or more fracture zones at a like plurality of different receiving

locations; and (c) analyzing the sensed responses at the different receiving locations to map the location of the one or more fracture zones.

[0149] Embodiment 15: The method of Embodiment 13 or Embodiment 14, further comprising moving the emitter to the different emission locations.

[0150] Embodiment 16: The method of any one of Embodiments 13 to 15, wherein each of the different receiving locations is a fixed distance from each of the respective emission locations.

[0151] Embodiment 17: The method of any one of Embodiments 13 to 16, further comprising deploying a distributed sensor in the well to sense the emissions and responses.

[0152] Embodiment 18: The method of any one of Embodiments 13 to 17, comprising moving an emitter-receiver tool in the well, the tool comprising the emitter and a receiver positioned at a fixed distance relative to the emitter.

[0153] Embodiment 19: The method of Embodiment 18, further comprising deploying a distributed sensor in the well to sense the emissions and responses.

[0154] Embodiment 20: The method of any one of Embodiments 13 to 19, comprising moving the emitter at a constant rate in the well, emitting the tube waves at evenly spaced time intervals, or a combination thereof.

[0155] Embodiment 21: The method of any one of Embodiments 13 to 20, wherein the plurality of emission locations comprise a first set of the emission locations above a first fracture and a second set of the emission locations below the first fracture.

[0156] Embodiment 22: The method of Embodiment 21, wherein the first set of emission locations is located intermediate the first fracture and an adjacent higher fracture, the second set of emission locations is located intermediate the first fracture and an adjacent lower fracture, or both of the first and second sets of emission locations are located intermediate respective adjacent higher and lower fractures.

[0157] Embodiment 23: The method of any one of Embodiments 13 to 22, wherein the plurality of receiving locations comprise a first set of the receiving locations above a first fracture and a second set of the receiving locations below the first fracture.

[0158] Embodiment 24: The method of Embodiment 23, wherein the first set of receiving locations is located intermediate the first fracture and an adjacent higher fracture, the second set of receiving locations is located intermediate the first fracture and an adjacent lower fracture, or both of the first and second sets of receiving locations are located intermediate respective adjacent higher and lower fractures.

[0159] Embodiment 25: The method of any one of Embodiments 13 to 24, further comprising sensing the emissions and/or responses at a surface receiver.

[0160] Embodiment 26: The method of any one of Embodiments 13 to 25, further comprising deploying the emitter on a wireline, coiled tubing, tractor, or a combination thereof.

[0161] Embodiment 27: The method of any one of Embodiments 13 to 26, further comprising planning a treatment of the well based on the mapped fracture locations.

[0162] Embodiment 28: The method of Embodiment 27, further comprising implementing the treatment in accordance with the plan.

EXAMPLES

[0163] FIGS. 4 and 5 provide a coiled tubing example, for the well configuration as shown in FIG. 2B, of the measurement of the emissions and reflections of a tube wave from the generator 34 traveling down coiled tubing 30 to the open-end emitter 32 and into the wellbore B, as measured by receiver 38 inside the coiled tubing near its open end and receiver 40 inside the tubing 30 at the surface. FIG. 5 represents an example where an open fracture is present, e.g., during or after fracturing or before, during, or after refracturing; FIG. 4, where the fracture is closed or absent, e.g., before treatment, or after placement of a diversion pill, or after an unsuccessful treatment or after losing conductivity following a period of production. The traces 100, 200 in FIGS. 4 and 100', 200' in FIG. 5 depict the readings from downhole receiver 38 and surface sensor 40, respectively, following generation of the signal from generator 34.

[0164] FIG. 4 depicts a case without the open fracture. The readings for the initial signal traveling down the coil 30 (FIG. 2B) are seen immediately by the surface sensor 40 in peak 202 and then by the downhole sensor 38 in peak 102. The coil end sends a reflection back to the surface sensor 40 seen as peak 204, and the bottom of the well sends a reflection which is seen by both sensors 38, 40 in peaks 106, 206, respectively.

[0165] FIG. 5 depicts a case where a fracture was introduced below the coil tubing end emitter 32 (FIG. 2B). The peaks 102, 202, 206 from the initial signal and tube end reflection are the same as in FIG. 3. Then, a reflection from the fracture appears in the peaks 108, 208. The peaks 106', 108' from the bottom of the well below the fracture are diminished with respect to the peaks 106, 108 in FIG. 4. Presence of open fracture pronounced in appearance of the peaks 108 and 208.

[0166] FIGS. 6A and 6B show an example using a moving emitter-receiver tool. FIG. 6A shows the configuration of the example well 300 with open fracture zones 302, 304, 306 at 2000 m, 2100 m and 2200 m, respectively, and a plug 307 at 2500 m. The fracture zones, 302, 304, 306 are prepared for refracturing, for example. A moving emitter-receiver assembly 308, which may be deployed on a wireline, coiled tubing, and/or tractor, etc., has a tube wave emitter 310 located 40 m below a receiver 312. The emitter 310 and the receiver 312 are moved in tandem above, between, and below the fractures 302, 3024, 306, serially creating and reading tube waves emitted at 4-meter increments for each successive reading.

[0167] FIG. 6B graphs the recordings of the readings taken from the sensor 312 (FIG. 6A) as the assembly 308 is moved in the well 300. The generally horizontal lines 320 in the graph display recording over time of the relative magnitude of response detected a pressure signal generated from an emission depth at every 4 meters. For example, the line 322 at 1950 meters displays a recording of the pressure signal generated by the emitter 310 at that depth with the sensor 312 at 1910 meters depth. Line 322 shows a direct wave 324 from the emitter 310 to the sensor 312 at 0.025 seconds and a reflection 326 from the 2000 m fracture 302 at 0.1 seconds.

[0168] A similar case for the source 310 at the depth 2016, where the emitter 310 is below the 2000-meter fracture 302, but the sensor 312 is still above the fracture 302, still displays the direct wave 328 at 0.025 seconds; however, the reflection 330 from the 2100-meter fracture 304 is delayed

to 0.14 seconds, indicating that the fracture **304** is farther away from the sensor at that depth. Similarly, the recording for the emitter **310** at the depth of 2050 meters captures a reflection **332** from the 2000-meter fracture at 0.05 seconds, and a reflection **334** from the 2100-meter fracture **304** at 0.1 seconds.

[0169] Taken together, the different reflections from the fractures **302**, **304**, **306**, are used to find the depth of the respective fractures **302**, **304**, **306**, which are generally unknown. As one example, the upwardly sloping line **336** is drawn along the reflections from the fracture **306** when it is below the emitter **310**, and the depth of the fracture **306** can be taken as the depth at the intersection **338** of the line **336** at the time of the direct wave (0.025 s), i.e., 2200 meters.

[0170] As another example, the depth of the top fracture **302** is determined as the 0.025-second intercept **342** of the downwardly sloping line **344**, less the spacing between the emitter **310** and receiver **312** (40 m), i.e., $2040 - 40 = 2000$ m. Completing the analysis, the 0.025-second intercept **346** confirms the depth of the upper fracture as 2000 m, and the 0.025-second intercept **348** suggests the middle fracture **304** has a depth at 2100 meters.

[0171] A similar analysis is used to determine the existence and/or depths of all the fractures in other wells as the characteristic points where the upwardly sloping lines along the times of reflections from a fracture below the emitter intercept a vertical line at the time of the direct wave (0.025 seconds in this example); and/or as the difference obtained by subtracting the emitter-receiver spacing (40 meters in this example) from the characteristic points where the downwardly sloping lines, along the times of reflections from a fracture below the emitter, intercept a vertical line at the time of the direct wave (0.025 seconds in this example). The analysis can be completed graphically by plotting the response time versus emitter depth, or by inputting the data into a computing device with the appropriate computational instructions, where the data can be the time/depth data points, or the raw data from the receiver.

[0172] The foregoing analysis technique for determine fracture depth can also be used to improve the accuracy of the depth determinations where some or all of the individual measurements from the respective signal waves are attenuated and/or relatively noisy, and/or to allow a relatively weak emission signal to be used. Stated differently, the tools, systems and methods herein can improve the signal to noise ratio. Further, a comparison of the strength or amplitude of the response can facilitate a determination of the relative degree of conductivity of each fracture zone.

[0173] The foregoing analysis can also be employed where the emitter is positioned above the receiver, with appropriate modification of the solution for the fracture depths according to the required treatment of the direct wave time and/or emitter-receiver spacing.

[0174] Although only a few exemplary embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this disclosure. For example, any embodiments specifically described may be used in any combination or permutation with any other specific embodiments described herein. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims. In the claims, means-plus-function clauses are intended to cover the structures described herein

as performing the recited function and not only structural equivalents, but also equivalent structures. Thus, although a nail and a screw may not be structural equivalents in that a nail employs a cylindrical surface to secure wooden parts together, whereas a screw employs a helical surface, in the environment of fastening wooden parts, a nail and a screw may be equivalent structures. It is the express intention of the applicant not to invoke 35 U.S.C. §112(f) for any limitations of any of the claims herein, except for those in which the claim expressly uses the words 'means for' or 'step for' together with an associated function without the recitation of structure.

What is claimed is:

1. A method to locate one or more fracture zones in a well, comprising:

- (a) emitting a plurality of tube waves from an emitter in the well from a like plurality of different emission locations;
- (b) sensing for respective responses to the tube waves from the one or more fracture zones at a like plurality of different receiving locations; and
- (c) analyzing the sensed responses at the different receiving locations to map the location of the one or more fracture zones.

2. The method of claim 1, further comprising moving the emitter to the different emission locations.

3. The method of claim 1, wherein each of the different receiving locations is a fixed distance from each of the respective emission locations.

4. The method of claim 1, further comprising deploying a distributed sensor in the well to sense the emissions and responses.

5. The method of claim 1, comprising moving an emitter-receiver tool in the well, the tool comprising the emitter and a receiver positioned at a fixed distance relative to the emitter.

6. The method of claim 5, further comprising deploying a distributed sensor in the well to sense the emissions and responses.

7. The method of claim 1, comprising moving the emitter at a constant rate in the well, emitting the tube waves at evenly spaced time intervals, or a combination thereof.

8. The method of claim 1, wherein the plurality of emission locations comprise a first set of the emission locations above a first fracture and a second set of the emission locations below the first fracture.

9. The method of claim 8, wherein the first set of emission locations is located intermediate the first fracture and an adjacent higher fracture, the second set of emission locations is located intermediate the first fracture and an adjacent lower fracture, or both of the first and second sets of emission locations are located intermediate respective adjacent higher and lower fractures.

10. The method of claim 1, wherein the plurality of receiving locations comprise a first set of the receiving locations above a first fracture and a second set of the receiving locations below the first fracture.

11. The method of claim 10, wherein the first set of receiving locations is located intermediate the first fracture and an adjacent higher fracture, the second set of receiving locations is located intermediate the first fracture and an adjacent lower fracture, or both of the first and second sets of receiving locations are located intermediate respective adjacent higher and lower fractures.

12. The method of claim 1, further comprising sensing the emissions and/or responses at a surface receiver.

13. The method of claim 1, further comprising deploying the emitter on a wireline, coiled tubing, or a combination thereof.

14. The method of claim 1, further comprising planning a treatment of the well based on the mapped fracture locations, and implementing the treatment in accordance with the plan.

15. A system to locate one or more fracture zones in a well, comprising:

- (a) an emitter movable in the well to emit tube waves at different emission locations in the well;
- (b) a downhole receiver adapted to sense respective responses to the tube waves at respective receiving locations a fixed distance relative to the emission locations; and
- (c) a recorder to track the time period between the emission of the tube waves and the sensed response for the different emission locations.

16. The system of claim 15, comprising a wireline, or coiled tubing carrying the emitter for deployment.

17. The system of claim 16, wherein the downhole receiver is carried on the wireline, or coiled tubing in a tandem arrangement at a fixed distance relative to the emitter.

18. The system of claim 17, wherein the emitter is connected to a free end of the coiled tubing and the down-

hole receiver is mounted inside the coiled tubing, outside the coiled tubing, or a combination thereof.

19. The system of claim 17, further comprising a distributed sensor in the well.

20. The system of claim 15, wherein the downhole receiver comprises a distributed sensor.

21. The system of claim 15, further comprising a surface receiver adapted to sense the tube wave emissions, the responses to the tube waves, or a combination thereof.

22. The system of claim 15, further comprising a controller to deploy the emitter to different depths in the well.

23. The system of claim 22, wherein the controller is adapted to deploy the emitter at a constant rate of travel and release a continuous tube wave emission from the emitter.

24. The system of claim 22, wherein the controller is adapted to release a tube wave emission from the emitter at spaced intervals.

25. A downhole tool for mapping fracture zones in a well, comprising:

- (a) a downhole assembly comprising:
 - a. an emitter to emit tube waves;
 - b. a receiver to sense responses to the tube waves characteristic of fracture zones; and
 - c. an elongated member carrying the emitter and the receiver in a tandem arrangement with a fixed relative spacing; and
- (b) a deployment system to move the downhole assembly to different depths selected from wireline, coiled tubing, and combinations thereof.

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