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(71) **Applicant** *(for FR only)*: **SERVICES PETROLIERS SCHLUMBERGER** [FR/FR]; 42 Rue Saint Dominique, F-75007 Paris (FR).

(71) **Applicant** *(for AL, AM, AU, AZ, BF, BG, BJ, BY, CF, CG, CI, CM, CO, CZ, DE, DK, GA, GN, GQ, GR, GW, HU, ID, IE, IL, IT, KG, KP, KR, KZ, LT, MD, ML, MR, MX, MY, NE, NO, NZ, OM, PL, QA, RO, RU, SI, SK, SN, TD, TG, TH, TJ, TM, TN, TR, TT, UZ, ZA only)*: **SCHLUMBERGER TECHNOLOGY B.V.** [NL/NL]; Parkstraat 83-89m, NL-2514 JG The Hague (NL).

(71) **Applicant** *(for GB, JP, NL only)*: **SCHLUMBERGER HOLDINGS LIMITED**; P.O. Box 71, Craigmuir Chambers, Tortola, Road Town, 1110 (VG).

(71) **Applicant** *(for CA only)*: **SCHLUMBERGER CANADA LIMITED** [CA/CA]; 525-3rd Avenue Southwest, Calgary, Alberta T2P-0G4 (CA).

(71) **Applicant** *(for all designated States except AU, CA, CO, CZ, DE, DK, FR, GB, GR, HU, ID, IE, IL, IT, KR, LT, MX, MY, NL, NO, NZ, OM, PL, QA, RO, SI, TN, TR, TT, US, UZ, ZA)*: **PRAD RESEARCH AND DEVELOPMENT LIMITED**; P.O. Box 71, Craigmuir Chambers, Tortola, Road Town, 1110 (VG).

(71) **Applicant** *(for IS only)*: **SCHLUMBERGER TECHNOLOGY CORPORATION** [US/US]; 300 Schlumberger Drive, Sugar Land, TX 77478 (US).

(72) **Inventors; and**
(75) **Inventors/Applicants** *(for US only)*: **ADIL, Abdur, Rahman** [PK/PK]; 7-C, 7th East Street, Phase 1, Defense Housing Authority, Sindh Karachi (PK). **BORISOVA, Elena** [RU/FR]; 8, Rue Littre, F-75006 Paris (FR). **MOSCATO, Tullio** [IT/FR]; 42 Rue Liancourt, F-75014 Paris (FR).

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(54) Title: METHODS AND APPARATUS FOR DETERMINING DOWNHOLE PARAMETERS

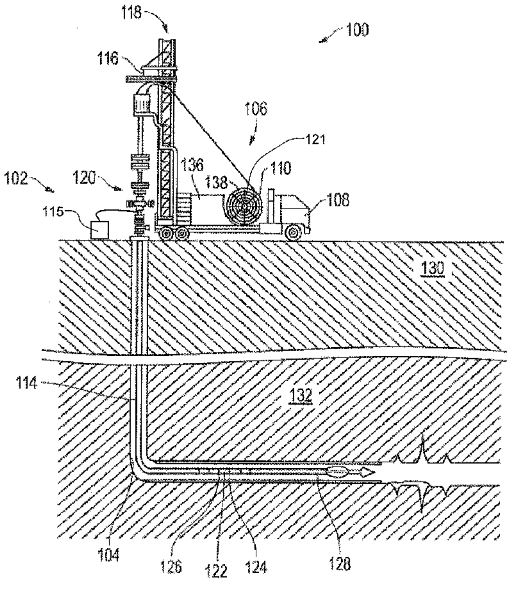

FIG. 1A

(57) **Abstract**: Apparatus and methods for determining downhole fluid parameters are disclosed herein. An example method includes deploying a downhole apparatus into a wellbore. The downhole apparatus includes a sensor including a heater and a temperature sensor. The example method also includes sending a signal to a downhole apparatus by changing a velocity of a fluid traversing the wellbore. The example method also includes detecting a change in the velocity of the fluid with the sensor and operating the downhole apparatus based on the change in velocity.

(74) **Agents**: **ABRELL, Matthias** et al.; Schlumberger IP-Administration, 10001 Richmond Avenue, 4th Floor, Houston, TX 77042 (US).

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METHODS AND APPARATUS FOR DETERMINING DOWNHOLE PARAMETERS

RELATED APPLICATIONS

[0001] This patent claims the benefit of U.S. Provisional Patent Application Serial Number 61/496,180, entitled "System and Method for Determining Downhole Fluid and Borehole Parameters," which was filed on June 13, 2011, and is incorporated herein by reference in its entirety.

BACKGROUND

[0002] A well may be drilled through a subterranean formation to extract hydrocarbons.

SUMMARY

[0003] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

[0004] An example method in accordance with the teachings of this disclosure includes deploying an apparatus in a conduit. The apparatus includes a sensor including a heater and a temperature sensor. The example method also includes sending a signal to the apparatus by changing a velocity of a fluid traversing the conduit. The example method also includes detecting a change in the velocity of the fluid with the sensor and operating the apparatus based on the change in velocity.

[0005] An example method in accordance with the teachings of this disclosure includes transmitting a signal between a downhole tool and a surface unit by changing a velocity of a fluid traversing a wellbore and detecting a change in the velocity of the fluid with a sensor having a heater and a temperature sensor.

[0006] An example method in accordance with the teachings of this disclosure includes pumping fluid at a first velocity, pumping fluid at a second velocity and detecting a change between the first and second velocities using a sensor. The sensor includes a heater and a temperature sensor. The change in velocity associated with data being transmitted.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] Embodiments of methods and apparatus for determining downhole parameters are described with reference to the following figures. The same numbers are used throughout the figures to reference like features and components.

[0008] FIG. 1A illustrates an example system in which embodiments of methods and apparatus for determining downhole parameters can be implemented.

[0009] FIG. 1B illustrates various components of an example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0010] FIG. 1C illustrates various components of the example device of FIG. 1B that can implement embodiments of the example methods and apparatus for determining downhole parameters.

[0011] FIG. 1D illustrates various components of another example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0012] FIG. 2A illustrates various components of an example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0013] FIG. 2B illustrates various components of the example device of FIG. 2A that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0014] FIG. 2C illustrates various components of the example device of FIG. 2A that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0015] FIG. 2D illustrates various components of another example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0016] FIG. 2E illustrates various components of yet another example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0017] FIG. 3 is a graph depicting sensor measurements taken using the example device of FIG. 2B.

[0018] FIG. 4A illustrates various components of an example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0019] FIG. 4B illustrates various components of an example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0020] FIG. 5A is a graph illustrating sensor measurements.

[0021] FIG. 5B is another graph illustrating sensor measurements.

[0022] FIG. 6 is a graph of sensor measurements and fluid flow based on the sensor measurements.

[0023] FIG. 7 illustrates various components of an example device that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0024] FIGS. 8 and 8A illustrate various components that can implement embodiments of the methods and apparatus for determining downhole parameters.

[0025] FIGS. 9 and 10 illustrate example method(s) for determining downhole parameters in accordance with one or more embodiments.

DETAILED DESCRIPTION

[0026] It is to be understood that the following disclosure provides many different embodiments or examples for implementing different features of various embodiments. Specific examples of components and arrangements are described below to simplify the present disclosure. These are, of course, merely examples and are not intended to be limiting. In addition, the present disclosure may repeat reference numerals and/or letters in the various examples. This repetition is for the purpose of simplicity and clarity and does not in itself dictate a relationship between the various embodiments and/or configurations discussed. Moreover, the formation of a first feature over or on a second feature in the description that follows may include embodiments in which the first and second features are formed in direct contact, and may also include embodiments in which additional features may be formed interposing the first and second features such that the first and second features may not be in direct contact.

[0027] Although some example fluid sensing systems disclosed herein are discussed as being positioned on treatment tools of a coiled tubing system, other examples are employed with and/or without treatment tools. For example, a fluid sensing element may be employed apart from the coiled tubing system. Thus, in some examples, the fluid sensing system may be deployed by a drill pipe, a drill string or any other suitable conveyance device.

[0028] The examples disclosed herein relate to methods and apparatus for communicating between uphole and downhole apparatus using velocity telemetry. In some examples, to send signals downhole, a velocity of a fluid traversing a wellbore is changed by changing a rate at which a pump pumps the fluid downhole. In some examples, to send signals uphole, a velocity of a fluid traversing the wellbore may be changed by changing a rate at which a pump pumps the fluid uphole. In either of these examples, based on a sensor identifying a change in a velocity of the fluid, an apparatus may receive an input, data, take an action, activate, etc. The sensor may include a heater and a temperature sensor.

[0029] FIG. 1A is a schematic depiction of a wellsite 100 with a coiled tubing system 102 deployed into a well 104. The coiled tubing system 102 includes surface delivery equipment 106, including a coiled tubing truck 108 with reel 110, positioned adjacent the well 104 at the wellsite 100. The coiled tubing system 102 also includes coiled tubing 114. In some examples, a pump 115 is used to pump a fluid into the well 104 via the coiled tubing. With the coiled tubing 114 run through a conventional gooseneck injector 116 supported by a mast 118 over the well 104, the coiled tubing 114 may be advanced into the well 104. That is, the coiled tubing 114 may be forced down through valving and pressure control equipment 120 and into the well 104. In the coiled tubing system 102 as shown, a treatment device 122 is provided for delivering fluids downhole during a treatment application. The treatment device 122 is deployable into the well 104 to carry fluids, such as an acidizing agent or other treatment fluid, and disperse the fluids through at least one injection port 124 of the treatment device 122.

[0030] The example treatment device 122 is optional and its use will depend on the various applications. The coiled tubing system 102 of FIG. 1A is depicted as having a fluid sensing system 126 positioned about the injection port 124 for determining parameters of fluids in the well 104. The fluid sensing system 126 is configured to determine fluid parameters, such as fluid direction and/or velocity. In other examples, other downhole parameters are determined.

[0031] In some examples, the coiled tubing system 102 includes a logging tool 128 for collecting downhole data. The logging tool 128 as shown is provided near a downhole end of the coiled tubing 114. The logging tool 128 acquires a variety of logging data from the well 104 and surrounding formation layers 130, 132 such as those depicted in FIG. 1A. The logging tool 128 is provided with a host of well profile generating equipment or implements configured for production logging to acquire well fluids and formation measurements from which an overall production profile may be developed. Other logging, data acquisition, monitoring, imaging and/or other devices and/or capabilities may be provided to acquire data relative to a variety of well characteristics. Information gathered may be acquired at the surface in a high speed manner, and, where appropriate, put to immediate real-time use (e.g. via a treatment application). Some examples do not employ the logging tool 128.

[0032] With reference still to FIG. 1A, the coiled tubing 114 with the treatment device 122, the fluid sensing system 126 and the logging tool 128 thereon is deployed downhole. As these components are deployed, treatment, sensing and/or logging applications may be directed by way of a control unit 136 at the surface. For example, the treatment device 122 may be activated to release fluid from the injection port 124; the fluid sensing system 126 may be activated to collect fluid measurements; and/or the logging tool 128 may be activated to log downhole data, as desired. The treatment device 122, the fluid sensing system 126 and the logging tool 128 are in communication with the control unit 136 via a communication link (FIGS. 1B-1D), which conveys signals (e.g., power, communication, control, etc.) therebetween. In some examples, the communication link is located in the logging tool 128 and/or any other suitable location. As described in greater detail below, the communication link may be a hardwire link or an optical link.

[0033] In the illustrated example, the control unit 136 is computerized equipment secured to the truck 108. However, the control unit 136 may be portable computerized equipment such as, for example, a smartphone, a laptop computer, etc. Additionally, powered controlling of the application may be hydraulic, pneumatic and/or electrical. In some examples, the control unit 136 controls the operation, even in circumstances where subsequent different application assemblies are deployed downhole. That is, subsequent mobilization of control equipment may not be included.

[0034] The control unit 136 may be configured to wirelessly communicate with a transceiver hub 138 of the coiled tubing reel 110. The receiver hub 138 is configured for communication onsite (surface and/or downhole) and/or offsite as desired. In some examples, the control unit 136 communicates with the sensing system 126 and/or logging tool 128 for conveying data therebetween. The control unit 136 may be provided with and/or coupled to databases, processors, and/or communicators for collecting, storing, analyzing, and/or processing data collected from the sensing system and/or logging tool.

[0035] In one example, the communication link between the treatment device 122, fluid sensing system 126 and/or logging tool 128 and the surface or control unit 136 may be implemented using a fiber optic or wired telemetry system. As such, the communication link/system may include tubing that provides and/or possesses a certain amount of stiffness in compression, similar to coiled tubing. In some such examples, a fiber optic tube is disposed inside coiled tubing. In some examples, a cross-sectional area of the fiber optic tube may be small relative to an inner area defined by the coiled tubing to limit a physical influence of the fiber optic tube on mechanical behavior of the coiled tubing during deployment and retrieval, thereby preventing “bird-nesting” or bundling within the coiled tubing. In some examples, optical fiber equipped coiled tubing is deployed into and retrieved from a wellbore at a greater speed than coiled tubing with wireline.

[0036] FIG. 1B illustrates an example communication link 200 between the treatment device 122, the fluid sensing system 126, the logging tool 128, and/or the surface or control unit 136. In the illustrated example, the communication link 200 includes a tubular 105 within which a duct or tube 203 is disposed. In the illustrated example, an optical fiber 201 is disposed in the tube 203. In some examples, more than one optical fiber is disposed in the tube 203. In the illustrated example, a surface termination 301 and a downhole termination 207 are provided to couple the optical fiber 201 to one or more devices or sensors 209. In some examples, the optical fiber 201 is a multi-mode optical fiber. In other examples, the optical fiber 201 is a single-mode optical fiber. The devices or sensors 209 are, for example, gauges, valves, sampling devices, temperature sensors, pressure sensors, distributed temperature sensors, distributed pressure sensors, flow-control devices, flow rate measurement devices, oil/water/gas ratio measurement devices, scale detectors, actuators, locks, release mechanisms, equipment sensors (e.g., vibration sensors), sand detection sensors, water detection sensors, data recorders, viscosity sensors, density sensors, bubble point sensors, composition sensors, resistivity array devices and sensors, acoustic devices and sensors, other telemetry devices, near infrared sensors, gamma ray detectors, H_2S detectors, CO_2 detectors, downhole memory units, downhole controllers, perforating devices, shape charges, firing heads, locators, and other devices.

[0037] FIG. 1C is a cross-sectional view of the communication link 200 of FIG 1B. Inside the tube 203, an inert gas such as nitrogen may be used to fill the space between the optical fiber or fibers 201 and the interior of the tube 203. In some examples, the fluid is pressurized to prevent the tube 203 from buckling. In some examples, a laser-welding technique is performed in an enclosed environment filled with an inert gas such as, for example, nitrogen to avoid exposing the optical fiber 201 to water or hydrogen during manufacturing. In some examples, the tube 203 is constructed by bending a metal strip around the optical fiber 201 and then welding that strip to form the tube 203. An example laser-welding technique is described in US Patent No 4,852,790, which is hereby incorporated herein by reference in its entirety. In some examples, gel including palladium or tantalum is inserted into an end of the tube 203 to separate hydrogen ions from the optical fiber 201 during transportation of the communication link 200.

[0038] Materials suitable for use in the tube 203 provide stiffness to the tube 203, are resistant to fluids encountered in oilfield applications, and/or are rated to withstand the high temperature and high pressure conditions found in some wellbore environments. In some examples, the tube 203 is a metallic material and the tube 203 may include metal materials such as, for example, InconelTM, stainless steel, or HasetloyTM.

[0039] In some examples, the tube 203 has an outer diameter of about 0.071 inches to about 0.125 inches. In some examples, the tube 203 is less than or equal to about 0.020 inches (0.508 mm) thick. The above-noted dimensions are merely examples and, thus, other dimensions may be used without departing from the scope of this disclosure

[0040] FIG. 1D illustrates another example communication link 212. In the illustrated example, the communication link 212 includes a tubular 105 and a first tube 203 and a second tube 203. A first optical fiber 201 is disposed in the first tube. A second optical fiber 201 and a third optical fiber 201 are disposed in the second tube 203. In some example, the first optical fiber 201 is coupled to one of the devices 209, and the second optical fiber 201 and the third optical fiber 201 are coupled to one or more other ones of the devices 209. In some examples, more than one of the devices 209 may be coupled to a single optical fiber 201.

[0041] FIGS. 2A-2C are schematic views of a portion of a coiled tubing system 202 with a treatment device 222 and fluid sensing system 226 on a coiled tubing 214 thereof, which may be used to implement the coiled tubing system 102, the treatment device 122 and/or the fluid sensing system 126 of FIG. 1A. FIG. 2A is a longitudinal view, partially in cross-section, depicting the fluid sensing system 226 positioned about the treatment device 222. As shown, the treatment device 222 has injection ports 224 for dispersing injection fluids into a well 204 as schematically depicted by the dashed arrows.

[0042] The injection fluid may be dispersed to treat a portion of a well 204, such as pay zone 240, to enhance production of fluid therefrom. As illustrated in FIG. 2A, stimulation fluid, such as acid, may be injected into the well 204 nearby the pay (or oil producing) zone 240 by means of the treatment tool 222. The acid is intended for the pay zone 240, but is shown positioned downhole therefrom. Precisely positioning the injection ports 224 against a zone of interest may be a challenging task due to uncertainties that may exist in target depth and/or tool position. The sensing system 226 around the injection port 224 may be tailored to measure a flow split upstream and downstream of the injection ports 224 in the well 204. Fluid movement may be used to indicate where the pay zone 240 is located relative to the injection port 224. Once known, the position of the treatment device 222 and the injection ports 224 may be positioned to affect treatment as desired.

[0043] As the fluid is released from the treatment device 222, the flow of the fluid is split with an upstream portion of the fluid moving upstream and a downstream portion of the injection fluid moving downstream. The upstream portion of the injection fluid travels upstream at a given velocity as indicated by the arrows labeled V1. The downstream portion of the injection fluid travels downstream at a given velocity as indicated by the arrows labeled V2. While the fluid is depicted as flowing in a specific direction, it will be appreciated that the flow of the fluid may vary with operating conditions.

[0044] While the example sensing system 226 illustrated in FIGS. 1 and 2A-2C is described in conjunction with the coiled tubing system 102 for determining fluid parameters, the sensing system 226 may also be used in other fluid flow applications such as, for example, detection of fluid cross-flow between zones, production logging (e.g., for single phase velocity, or in conjunction with Flow Scanner Imaging (FSI) complementary to a spinner in a low velocity range), downhole or surface testing in conjunction with use of a flowmeter (e.g., low speed Venturi based flowmeter applications), leakage detection (e.g., with dynamic seals), with other tools where flow velocity measurements is desired, among others. The sensing system 226 may be positioned on any surface, downhole and/or other movable equipment, such as a downhole tool, and/or in fixed equipment, such as a casing (not shown).

[0045] The sensing system 226 is depicted in FIG. 2A as having a plurality of sensor elements 242a,b positioned about the treatment device 222. In some examples, one or more sensor elements 242 a,b are positioned about the coiled tubing system 102 to perform fluid and/or other downhole measurements. In some such examples, the sensor elements 242a,b are positioned about the injection port(s) 224 to measure fluid parameters. The fluid measured is the injection fluid dispersed from the treatment device 222, but may also include other fluids in the well (e.g., water, hydrocarbons, gases, etc.) that mix with the injection fluid as it is dispersed.

[0046] An upstream portion of the sensor elements 242a are depicted as being positioned on the treatment device 222 a distance upstream therefrom. A downstream portion of the sensor elements 242b are depicted as being positioned on the treatment device 222 a distance downstream therefrom. The upstream sensor elements 242a and/or the downstream sensor elements 242b may be arranged radially about the treatment apparatus 222. In the illustrated example of FIG. 2B, the sensor elements 242a,b are positioned at various radial locations x,y,z about the treatment apparatus 222. While a specific configuration for the sensor elements 242a,b is depicted in FIGS. 2A and 2B, it will be appreciated that one or more sensor elements may be positioned at various locations (longitudinally and/or radially) about the coiled tubing system 202 and/or well 204.

[0047] At least some of the sensor elements 242a,b are capable of sensing fluid parameters, such as fluid direction and velocity. In some examples, more than one of the sensor elements 242a,b may be capable of measuring the fluid parameters. In some examples, at least one of the sensor elements 242a for measuring fluid parameters is positioned upstream from the injection port 224, and at least one of the sensor elements 242b for measuring fluid parameters is positioned downstream from the injection port 224. In this configuration, the measurements of the upstream and the downstream fluid sensors 242a,b may be compared to determine fluid parameters, such as fluid direction and/or fluid velocity. The ratio between upper and lower velocities and fluid direction obtained from measurements of the upstream and downstream sensing elements 242a,b may be used to generate real-time monitoring of where the fluid is flowing during the treatment, as will be described further herein. Other downhole parameters may also optionally be measured with the fluid sensing system 226 and/or other sensors positioned about the well.

[0048] Comparison of multiple sensing elements 242a,b may be used to account for differences in measurements taken by the various sensing elements 242a,b. In some examples, multiple sensing elements 242a,b are used to provide sufficient redundancy and confidence in the measurement results. This redundancy may also reduce the severity of impact where one or more sensor elements 242a,b fails, such as in harsh downhole environments involving the use of acids. The multiple sensing elements 242a,b may also be used to generate fluid direction and/or velocity information. In such cases, at least one upstream sensor element 242a and at least one downstream sensor element 242b may be used. In some examples, additional sensor elements 242a,b are provided to enhance reliability of the values generated.

[0049] In some examples, it may be useful to consider the position of the sensing element 242a,b about the treatment tool 222. The number of arrays (or sets of sensing elements 242a,b), as well as the number of sensing elements 242a,b per array, may vary. As shown in FIG. 2A, the sensing elements 242a,b are positioned upstream and downstream to measure fluid as it passes upstream and downstream from the injection ports 224. In some examples, when using corresponding upstream and downstream sensing elements 242a,b, the corresponding sensing elements 242a,b, are positioned at equal distances from the injection port 224. In some examples, corresponding sensing elements 242a,b are identically matched. Matched sensing elements may be spaced at equal distances.

[0050] In the illustrated example, multiple sensing elements 242a,b are also positioned about the circumference of the tool at 90-degree intervals x, y, and z as shown in FIG. 2B. As shown in FIG. 2B, the sensing elements 242b are positioned at radial locations x, y and z about the treatment device 222. The sensing element 242b at position x is against a wall 205 of the well 204. The azimuthal arrangement of sensing elements 242a,b at positions x, y, and z provides redundancy in case one side of measurements is impeded.

[0051] An issue may appear when the tool body (e.g., the treatment tool 222) is eccentric (or not concentric) with the well 204 as shown in FIG. 2B. In the illustrated example, the sensing element $242b_x$ located closer to the wall 205 of the well 204 may read a lower flow value than the sensing elements $242b_y$, $242b_z$ positioned farther from the wall. In such cases, it may be desirable to ignore or remove measurements from potential obstructed sensing elements, such as the sensing element $242b_x$.

[0052] As shown in FIG. 2B, the sensing elements 242b are positioned on an outer surface 223 of the treatment tool 222. The sensing elements 242b may be flush with the outer surface 223, recessed below the outer surface 223 or extended a distance therefrom. In some examples, the sensing elements 242b are positioned such that each sensing element 242b contacts fluid for measurement thereof, but remains protected. To prevent damage in harsh downhole conditions, protrusion of the sensing elements 242b from the treatment tool may be reduced. As shown in FIG. 2C, the sensing elements 242b may also be positioned inside the treatment tool 222, for example, on an inner surface 225 thereof.

[0053] FIGS. 2D and 2E illustrate other portions of the coiled tubing system 202 including the fluid sensing system 226, which may be used to implement the example coiled tubing system 102 of FIG. 1A. In FIG. 2D, the example sensing system 226 is disposed at a lower end of the coiled tubing 114.

[0054] In FIG. 2E, the example sensing system 226 is disposed between the logging tool 128 and the treatment tool 122. In the illustrated example, the logging tool 128 is disposed above the sensing system 226 and the treatment tool 122 is disposed below the sensing system 226 in the orientation of FIG. 2E. In some examples, the fluid enters the well 104 as shown by arrows V3. In other examples, the sensing system 226 is disposed at one or more other locations on the coiled tubing 114.

[0055] FIG. 3 is a graph 350 depicting sensor data taken from the example sensing elements 242b of FIG. 2B. The graph 350 plots flow velocity (x-axis) as a function of sensor output (y-axis) for sensing elements $242b_x$, $242b_y$, and $242b_z$ at positions x, y and z, respectively. As depicted by the graph 350, the flow velocity of the sensing elements $242b_y$ and $242b_z$ at positions y and z are different from the flow velocity of the sensing element $242b_x$ at position x. In other words, readings of the top sensing element $242b_z$ and the 90-degree sensing element $242b_y$ are substantially consistent in determining the flow velocity. However the bottom sensing element $242b_x$ has a flow velocity that is lower.

[0056] The graph 350 indicates that the sensing element $242b_x$ at position x is pressed against the wall 205 of the well 204 and is unable to obtain proper readings. Thus, the measurements depicted by line $242b_x$ taken by sensing element 242b at position x may be disregarded. The measurements depicted as lines $242b_y$ and $242b_z$ taken by sensing elements 242b at positions y and z, respectively, may be combined using conventional analytical techniques (e.g., curve fitting, averaging, etc.) to generate an imposed flow 244. Thus, by placing several sensing elements 242a,b azimuthally around the circumference of a tool and detecting the lowest reading sensing element (e.g., $242b_x$), the azimuth of a flow obstruction may be determined. The sensing element located opposite to the lowest-reading sensing element (e.g., $242b_y$), or combinations of other sensing elements, may then be used to perform the flow measurement.

[0057] FIGS. 4A and 4B are schematic views of sensing elements 442p and 442q usable as the sensing elements 242a,b of FIGS. 2A and 2B. Each of the sensing elements 442p,q has a heater 454p,q and a sensor 456p,q, respectively, positioned in a sensor base 452. In the illustrated example, the sensor 456p,q is a temperature sensor (or temperature sensor) capable of measuring fluid temperature.

[0058] In some examples, the sensor elements 442p,q are calorimetric type flow sensors (or flow meters) that have two sensing elements such as, for example, a sensor for velocity measurement (scalar sensor) and a sensor for directional measurement (vector sensor). The heater 454p,q and the temperature sensor 456p,q interact to operate as velocity (or scalar) and directional (or vector) sensors.

[0059] To determine fluid velocity, the sensing elements 442p,q act as calorimetric sensors. The heater 454p,q (or hot body) of each sensor elements 442p,q is placed in thermal contact with the fluid in the well 104. The rate of heat loss of the heater 454p,q to the fluid is a function of the fluid velocity as well as thermal properties. A heat dissipation rate of the heater 454p,q may be measured, and a flow velocity can be determined for a known fluid. The heater 454p,q generates heat (e.g., from electricity), and dissipates the heat to the fluid in contact. The rate of heat generation and the temperature may be readily measurable during operation.

[0060] The temperature sensor 456p,q may be used to monitor ambient temperature of the fluid, while the heater 454p,q measures its own temperature during heating. The difference between the temperature of the heater 454p,q and the ambient temperature of the fluid is defined as temperature excursion. The temperature excursion, ΔT, may be written as follows:

Equation (1): $$\Delta T = T_h - T_a.$$

In Equation 1, T_a represents the ambient temperature of the fluid as measured by the temperature sensor; T_h represents the temperature of the heater; and the temperature excursion is proportional to the heater power at a given flow condition. A thermal property between the heater and the fluid such as, for example, thermal conductance, G_{th}, may be calculated according to following expression:

Equation (2): $$G_{th} = \frac{P}{T_h - T_a} = \frac{P}{\Delta T}.$$

[0061] In Equation 2, P represents the heater power in steady state. The inverse of this proportionality (or the thermal conductance) correlates the flow velocity V_{flow} because V_{flow} is a function of G_{th}. As provided by Equation 1, the thermal conductance is determined from three quantities: P (the heater power), T_h (the temperature of the heater) and T_a (the temperature of the fluid ambient). The quantities may be measured in steady state. Theoretically, the amount of power or temperature excursion used during measurement is immaterial to resultant thermal conductance. However, power and temperature excursion may affect accuracy because physical measurements have limits. In some cases, such as the configuration of FIG. 4B, a ΔT of a few degrees in Kelvin (K) may be considered appropriate.

[0062] In other examples, other thermal properties such as, for example, a normalized power dissipation are calculated to determine the flow velocity. The normalized power dissipation may be calculated according to the following expression:

Equation (3): $\frac{P}{S(T_h - T_a)}$.

In Equation 3, the normalized power dissipation is calculated by dividing the power of the heater by the temperature excursion and an area of a heating surface of the sensor, S.

[0063] The measurements taken by the calorimetric sensing elements 454p,q may be used obtain the heater-fluid thermal conductance, the normalized dissipated power, and/or other thermal properties. A measurement technique may involve either constant excursion or constant power. For the constant excursion technique, power sent to the heater may be regulated by electronics (e.g., the control unit 136) such that the heater temperature may be maintained at a constant excursion above the fluid ambient temperature. In steady state, the power measured is monotonically related to the thermal conductance, the normalized power dissipation, and/or other thermal properties. For the constant power technique, the heater may be supplied with a constant and predetermined power, while the heater temperature T_h varies and may be determined by flow velocity.

[0064] FIG. 5A is a graph 657 depicting a flow response of a calorimetric sensor, such as the sensing elements 442a,b depicted in FIGS. 4A and 4B. The resulting thermal conductance verses flow curve 658 demonstrates that thermal conductance is non-linear relative to the flow velocity.

However, the thermal conductance verses flow curve 658 is monotonic. Therefore, a correlation can be established to invert the measurement, and the flow velocity can be obtained as described in conjunction with Equations 1-3.

[0065] The measurement of flow velocity is a measurement of the thermal conductance, the normalized power dissipation, and/or other thermal properties between the heater 454p,q and the fluid. The measurement of thermal conductance and/or the normalized power dissipation may be determined with constant temperature excursion (ΔT) or constant heater power. The constant temperature excursion may regulate temperature. The constant heater power may regulate power. Either measurement technique may involve the heater 454p,q and the temperature sensor 456p,q.

[0066] Referring back to FIGS. 4A and 4B, the sensing elements 442p,q may also act as scalar sensors to determine fluid direction. In the illustrated example, the sensing elements 442p,q are capable of acting as both calorimetric sensors for determining fluid velocity and vector sensors for measuring fluid direction. Calorimetric sensors may be unable to determine fluid direction. In such examples, the calorimetric sensors may respond to fluid velocity regardless of direction. Fluid direction may be acquired by a second measurement, such as by using vector sensors capable of fluid direction detection. Fluid direction may also be acquired by, for example, the sensing elements 442p,q of FIGS. 4A and 4B configured for measurement of both fluid velocity and direction. Physics that enables directional detection may also involve detection of asymmetry in temperature between upstream and downstream sensing elements (e.g., caused by heat from the heater 454p of the upstream sensing element), such as the upstream sensing elements 242a and the downstream sensing elements 242b of FIG. 2A.

[0067] FIGS. 4A and 4B depict configurations of the sensing element 442p,q capable of detecting both fluid flow rate and direction. FIG. 4A depicts a thermocouple (TC) sensing element 442p. FIG. 4B depicts a dual sensing element 442q. The base 452 for each sensing element 442p,q is sized for hosting the heater 454p,q, the sensor 456p,q and/or other devices therein.

[0068] In some examples, the base 452 has a minimum thickness, or is recessed in the downhole tool, to prevent damage in the well 104. The sensor base 452 is positionable downhole, for example, on the treatment device 122, 222 and/or the coiled tubing 114, 214 (FIGS. 1, 2A, 2B). The base 452 may be round as shown in FIG. 4A or rectangular as shown in FIG. 4B. The base 452 may be made of epoxy, PEEK molding and/or any other material.

[0069] The heater 454p,q and the temperature sensor 456p,q may be positioned in close proximity in base 452, but are thermally isolated from each other. In the illustrated example, because the heater 454p,q creates a temperature gradient in the fluid, the temperature sensor 456p,q is provided with sufficient thermal isolation from the heater 454p,q to prevent the temperature sensor 456p,q from being disturbed by the heat flux of the heater 454p,q or thermally coupling with the heater 454p,q, which may result in an erroneous measurement value. The temperature sensor 456p,q may optionally be positioned in a separate package spaced from the heater 454p,q.

[0070] The TC sensing element 442p of FIG. 4A is depicted as having a pair of TC junctions (or sensors) $456p_{1,2}$ on either side of a heating pad (or heater) 454p. The TC junctions $456p_{1,2}$ are linked by a metal wire 460. Each TC junction $456p_{1,2}$ has a TC pad with leads 462a,b extending therefrom. In some examples, the leads 462 are also wires operatively coupled to a controller 436 for operation therewith.

[0071] The TC junctions 456p positioned on either side of the heater 454p may be used to detect a temperature imbalance therebetween, and convert it into a TC voltage. A small voltage is present if the two TC junctions $456p_{1,2}$ are at a different temperatures. The TC junctions $456p_{1,2}$ are positioned very close to the heater 454p (one on each side) for maximum contrast of temperature. At zero flow, the heater 454p may heat up both TC junctions $456p_{1,2}$. However, the heating does not produce voltage.

[0072] Two metal pads 464p are depicted as supporting the TC junctions $456p_{1,2}$. The metal pads 464p may be provided to improve the thermal contact between the TC junctions $456p_{1,2}$ and the fluid. The metal pads 464p may be useful in cases where the TC junctions $456p_{1,2}$ are of a small size. The metal pads 464p and the TC junctions $456p_{1,2}$ may be held together by thermal adhesives such as silver epoxies or any other thermally conductive adhesives. The metal pads 464p are positioned in alignment with the heater 454p, thereby defining a flowline 466p along the sensing element 442p as indicated by the arrow.

[0073] TC voltage (y-axis) as a function of flow velocity (x-axis) is show in a graph 659 of FIG. 5B. The graph 659 exhibits an odd function of the flow velocity measured by the TC junctions $456p_{1,2}$. The magnitude of a maxima near zero flow tapers off gradually with increasing velocity. At zero crossing, the TC signal output undergoes an abrupt change in polarity from negative to positive as indicated by curves 661a,b, respectively. This change in signal polarity may be used to detect the fluid direction as described in greater detail below.

[0074] The temperature profile along a flow stream of, for example, the sensing element 442p is shown schematically in FIG. 6. FIG. 6 is a graph 663 depicting temperature (y-axis) versus velocity (x-axis). As depicted by this graph, the heater 454p generates a constant heat T_h measurable by the TC junction $456p_{1,2}$ on either side thereof. Heat from the heater 454p is carried downstream by the fluid forming a hot stream. The velocity V1, V2 and V3 are measured at, for example, different time intervals. Visibility of the thermal gradient may depend on the velocity.

The thermal gradient between upstream and downstream is detectable with the sensor element 442p. This creates a temperature contrast between the upstream and downstream TC junctions 456$p_{1,2}$. This indicates that the flow is moving towards the TC junctions 456p_2, thereby indicating fluid flow direction. By detecting asymmetry between the TC junctions 456$p_{1,2}$, the fluid direction can be determined as indicated by the arrow.

[0075] The dual-element sensing element 442q of FIG. 4B is depicted as having two identical elements (sensors/heaters) 456q/454q. The sensors/heaters 456q/454q are depicted as Element M and Element N in the sensing element 442q. In some examples, the heater 454q and the sensor 456q (and, therefore, Elements M and N) are interchangeable in function and operation. In some such cases, the sensor 456q is capable of performing the functions of the heater and the heater 454q is capable of performing the functions of the sensor. The Elements M and N are operatively linked via links 455 to the controller 436 for operation therewith.

[0076] In some examples, a desired measurement may be operated in self-referenced mode in which a single Element M or N plays a dual role, both as heater and as temperature sensor. In some such cases, the heater and the temperature sensor may utilize a time multiplexing technique. In some examples, the role of the heater 454q and temperature sensor 456q may be reassigned at anytime. This measurement scheme may be used to provide flexibility in designing and/or operating the sensor element 442q, which may be tailored to a particular application.

[0077] An asymmetry of temperature between the identical Elements M and N is detectable by the dual-element sensor 442q. The two identical Elements M and N are positioned along a line of flow of the fluid as indicated by the arrow. The Elements M and N may be positioned in close proximity, for example, within the same base (or package) 452.

[0078] Measurement by the sensor element of FIG. 4B may be achieved using various methods. A first method involves measuring the heater power in flow using Element M as the heater and Element N as the temperature sensor. After a stable reading is attained, the roles of Elements M and N interchange and the measurement is repeated. Comparing the power of the two measurements, fluid direction can be ascertained. The heater that consumes more power is located upstream, provided that the flow does not vary in the meantime. A second method that may be used involves measuring by heating both elements M and N simultaneously with the same amount of power. The measurements of each element may be compared. Whichever element reveals a higher temperature is downstream in the direction of the fluid flow. A third method that may be used involves watching the temperature of Element M while switching on and off Element N at a certain power level. If an alteration of temperature is noticed, Element N may be assumed to be upstream of Element M. No change may suggest otherwise.

[0079] With the first two methods, where quantities are compared across Elements M and N, a good match of characteristics of the two elements M, N reduces potential errors. The match of elements may be achieved by calibration and normalization. The third method, on the other hand, may be used without as good of a match. Dual-element sensors are usable, for example, for bi-directional flow.

[0080] When the temperature sensor 456p,q and the heater 454p,q of FIGS. 4A and 4B reside in the same package (for instance, due to space constraint), the temperature sensor 456p,q is positioned upstream of the heater 454p,q (or element M is upstream of Element N). If flow goes in both directions, the temperature sensor 456p,q and heater 454p,q (or Elements M and N) may be positioned in a side-by-side (or flowline) configuration in line with the flow of the fluid as shown in the sensing elements 442p,q of FIGS. 4A and 4B.

[0081] While FIG. 4A depicts a single heater 454p with a pair of TC junctions 456p and FIG. 4B depicts a single heater 454p with a single temperature sensor 456q, other examples employ multiple heaters 454p,q and/or sensors 456p,q. Additional sensors and/or other devices may be incorporated into the sensing elements 442p,q and/or used in combination therewith. In sensor systems including multiple heaters 454p,q, one temperature sensor 456p,q can serve multiple heaters 454p,q. Some multi-elements sensors have more than two elements (e.g., M, N, P, D . . .). As shown in FIG. 4B, a third element O may be provided. In another method of measurement, the three or more elements (e.g., M, N, O) may be used to detect fluid direction by heating a middle element and comparing the temperature between upstream and downstream elements thereabout.

[0082] As shown, the sensing elements 442p,q of FIGS. 4A and 4B (and/or the sensors, heaters, elements and/or other components used therein and/or therewith) are operatively coupled to the controller 436 for providing power, collecting data, controlling and/or otherwise operating the sensing element 442p,q. The controller 436 may be, for example, the logging tool 128, the control unit 136 and/or other electronics capable of providing power, collecting data, controlling and/or otherwise operating the temperature sensors 456p,q, heater 456p,q and/or other elements of the sensing elements 442p,q. The power sources may be batteries, power supplies and/or other devices internal to and/or external to the sensing elements. In some cases, other devices such as the logging tool 128 of FIG. 1A may provide power thereto. Such electronic devices may be internal and/or external to the sensing elements. Communication devices may be provided to wire and/or wirelessly coupled the sensing elements to downhole and/or surface communication devices for communication therewith. In some cases, communication devices, such as transceivers may be provided in the sensing elements. In other cases, the sensing elements may be linked to the logging tool 128 (FIG. 1A) or other devices for communication as desired.

[0083] The sensing elements are also operatively coupled to and/or in communication with databases, processors, analyzers, and/or other electronic devices for manipulating the data collected thereby. The power, electronic and/or communication devices may be used to manipulate data from the sensing elements, as well as other sources. The analyzed data may be used to make decisions concerning the wellsite and operation thereof. In some cases, the data may be used to control the well operation. Some such control may be done automatically and/or manually as desired.

[0084] While elements of the heater and the temperature sensor may be physically identical, the sensor can have a variety of types, forms and/or shapes. FIG. 7 depicts the sensor 770 usable as an element of the sensor elements 454p,q of FIGS. 4A and/or 4B. FIG. 7 depicts the sensor 770 usable as the heater 454q and/or the temperature sensor 456q, as elements M, N and/or O, or in combination therewith. A shown, the sensor 770 is positionable in the base 452. The sensor 770 may be operatively coupled to the controller 436 via wires 774 for operation therewith in the same manner as previously described for the sensor elements 442p,q.

[0085] The example sensor 770 of FIG. 7 is an RTD type sensor with a resistance that varies with temperature. In some examples, the sensor 770 is used for temperature sensing purposes. However, the sensor 770 may generate heat when current passes through the sensor 770. Thus, the example sensor 770 can be used both as a heater and a temperature sensor (e.g., 454p,q and 456p,q of FIG. 4B).

[0086] A thin-film type RTD capable of use as both a heater and temperature sensor may be used so that it can interchangeably operate as the Element M, N and/or O of FIG. 4B. As shown in FIG. 7, the sensor 770 positioned in the base 452 has a front surface (or contact surface) 772 positionable adjacent the fluid for taking measurements therefrom. In some examples, the sensor 770 employs platinum in the form of either wire or thin film (or resistor) 774 deposited on a heat-conductive substrate 776, such as sapphire or ceramic. The wire 774 is positioned in the film 776 and extends therefrom for operative linkage with the controller 436. The heat-conductive substrate 776 may be adhered or bonded to a thin pad 778 (made of, for example, Inconel or ceramic substrate) by a thermally conductive adhesive 780, such as silver epoxy, or by brazing. In some examples, such bonding provides low thermal resistance.

[0087] In the illustrated example, the sensor 770 is wrapped in protective packaging, but they may differ by thermal mass and, hence, response time. The shape of the pad 778 may be square, circular or any other shape capable of supporting the RTD in the base 452. In some examples, the pad 778 has a dimension of about 10 mm (or more or less), and a thickness sufficient for mechanical viability. The thickness and material selected may determine the performance of heater-fluid thermal contact.

[0088] The example sensor 770 may be configured with a large surface area for contact with the fluid and/or large thermal mass for passage of heat therethrough. A larger thermal mass may result in a relatively slower measurement response. However, the thermal mass may also assist in reducing (e.g., averaging out) spurious variations in readings caused by turbulence. Sensor electronics may also be provided to reduce spurious variations.

[0089] The sensor 770 and/or the sensing element 442q may be configured in a surface (or non-intrusive) form with a low profile (or thickness) as shown in FIGS. 7 and 4B. The sensor 770 and/or the sensing element 442q may be positionable downhole via a downhole tool (e.g., coiled tubing system 102 of FIG. 1A) extending a small distance (if any) therefrom. This low profile or non-intrusive surface form may be provided to reduce the disturbance to the fluid flowing across the sensor, while still allowing for measurement of the fluid. Moreover, the low profile surface form may also be configured to limit the amount of protrusion from the downhole the tool and, therefore, potential damage thereto.

[0090] Another example embodiment of using the previously described sensor elements 242 and apparatuses is shown in Figure 8. Figure 8 depicts an example apparatus to provide a method of communicating with a downhole apparatus or logging tool 128 using changes in velocity. The downhole apparatus or logging tool 128 may be part of a completion or permanent installation or may be or may be part of a more typical logging tool that is temporarily disposed in the wellbore. It is also contemplated that the method of communicating may be used in a non-downhole environment, such as in a subsea environment or a surface environment such that the fluid flow traverses a conduit, in addition to or instead of, a wellbore. As such, the method of communicating may also be used in a non-oilfield service environment. In either case, the method of communicating described hereafter may be a primary method of communication between an apparatus at a first location and an apparatus at a second location, or may be a secondary or redundant method of communication between the same. For example, the logging tool 128 may be disposed downhole as or along with any kind of other tool. However, the sensors 242 and/or sensing system 226 in this embodiment, as seen in Figure 8A, is used as part of the communication link between the downhole tool 128 and the surface unit 136. Specifically, the coiled tubing system 102 may include a pumping system that allows for fluids such as mud, for example, to be pumped into the well 104 through the tubing 114. The pumping system would have the ability to change the velocity of the fluid as it is pumped into the well. The control unit 136 could thus be communicably coupled to the pumping system and would be able to send communications downhole via the velocity changes. In turn, the sensors 242 and/or sensing system 226 as seen in Figure 10A which may be located inside or outside the tubing 114, would sense the change in velocity, which could be used to control or generally communicate with the logging tool 128. With additional hardware, such as a pump, valve system, and additional sensors 242, a similar communication could be accomplished from downhole to the surface.

[0091] FIGS. 9, 10 are flowcharts representative of example methods disclosed herein. At least some of the example methods of FIGS. 9, 10 may be carried out by a processor, the logging tool 128, the controller 436 and/or any other suitable processing device. In some examples, at least some of the example methods of FIGS. 9, 10 are embodied in coded instructions stored on a tangible machine accessible or readable medium such as a flash memory, a ROM and/or random-access memory RAM associated with a processor. Some of the example methods of FIGS. 9, 10 may be implemented using any combination(s) of application specific integrated circuit(s) (ASIC(s)), programmable logic device(s) (PLD(s)), field programmable logic device(s) (FPLD(s)), discrete logic, hardware, firmware, etc. Also, one or more of the operations depicted in FIGS. 9, 10 may be implemented manually or as any combination of any of the foregoing techniques, for example, any combination of firmware, software, discrete logic and/or hardware.

[0092] Further, although the example methods are described in reference to the flowcharts illustrated in FIGS. 9, 10, many other methods of implementing the example methods may be employed. For example, the order of execution of the blocks may be changed, and/or some of the blocks described may be changed, removed, sub-divided, or combined. Additionally, any of the example methods of FIGS. 9, 10 may be carried out sequentially and/or carried out in parallel by, for example, separate processing threads, processors, devices, discrete logic, circuits, etc.

[0093] FIG. 9 illustrates an example method 900 disclosed herein that may be used to determine one or more fluid parameters. At block 902, a downhole system such as, for example, the coiled tubing system 100 of FIG. 1A is deployed into a well with a sensor (e.g., one of the example sensor elements 242a,b of FIG. 2A) thereon. In some examples, the sensor includes a heater (e.g., the example heater 454 of FIG. 4, the example RTD sensor 770 of FIG. 7) and a temperature sensor (e.g., the example temperature sensor 456 of FIG. 4, the example RTD sensor 770 of FIG. 7). At block 904, fluid is injected from the downhole system into the well via an injection port (e.g., the example injection port 224 of FIG. 2) of the downhole system.

[0094] At block 906, a first measurement (e.g., a temperature of the fluid) is taken with the temperature sensor. At block 908, a second measurement (e.g., power dissipated via the heater, a temperature of the heater, etc.) is taken with the heater. At block 910, a fluid parameter (e.g., a fluid velocity, a direction of fluid flow) is determined based on the first measurement and the second measurement. At block 912, the fluid parameter is analyzed. In some examples, the measurements and/or the parameter are stored, processed, reported, and/or manipulated, etc.

[0095] FIG. 10 illustrates an example flow chart 1000 that may be used to implement the examples disclosed herein. The example process may begin by deploying a downhole apparatus and/or tool into a wellbore (block 1002). To communicate and/or convey data between the downhole apparatus and a surface unit, a signal may be transmitted between the downhole apparatus and the surface unit (block 1004). In some examples, the signal is associated with a change in velocity in fluid traversing the wellbore. In some such examples, to send a signal from the surface unit to the downhole apparatus, a surface pump may pump fluid downhole a first rate and then pump fluid downhole at a second rate. In other such examples, to send a signal from the downhole apparatus to the surface unit, a dowhole pump may pump fluid uphole at a first rate and then pump fluid uphole at a second rate. In either of these examples, the change in the velocity is detected by a sensor including a heater and a temperature sensor and/or a processor receiving input from the sensor (block 1006).

[0096] When transmitting signals and/or data uphole, the sensor may be positioned on an exterior surface and/or interior surface of pipe, coiled tubing, etc., proximate and/or in communication with a processor and/or control unit at the surface. When transmitting signals and/or data downhole, the sensor may be positioned on an exterior surface and/or an interior surface of the downhole apparatus. In such examples, based on identifying a change in the velocity, the downhole apparatus may operate, preform a task, take an action, activate etc. (block 1008).

[0097] An example method includes deploying a downhole apparatus into a wellbore. The downhole apparatus includes a sensor including a heater and a temperature sensor. The method also includes sending a signal to a downhole apparatus by changing a velocity of a fluid traversing the wellbore and detecting a change in the velocity of the fluid with the sensor. The method also includes operating the downhole apparatus based on the change in velocity.

[0098] In some examples, operating the downhole apparatus includes activating the downhole apparatus. In some examples, the fluid is wellbore fluid pumped downhole by a surface pump. In some examples, the sensor is positioned adjacent an interior surface of the downhole apparatus. In some examples, the sensor is positioned adjacent an exterior surface of the downhole tool. In some examples, sending the signal to the downhole apparatus includes sending a signal from a surface unit to the downhole apparatus.

[0099] Another example method includes transmitting a signal between a downhole tool and a surface unit by changing a velocity of a fluid traversing a wellbore and detecting a change in the velocity of the fluid with a sensor having a heater and a temperature sensor. In some examples, the signal is associated with a measurement obtained downhole. In some examples, the downhole apparatus includes the sensor. In some examples, the method also includes operating the downhole apparatus based on the signal. In some examples, the sensor is positioned adjacent an interior surface of the downhole apparatus. In some examples, sensor is positioned adjacent an exterior surface of the downhole tool. In some examples, the sensor is coupled to a pipe proximate the surface unit. In some examples, the downhole apparatus comprises a logging tool. In some examples, transmitting the signal includes transmitting the signal from the surface unit to the downhole apparatus. In some examples, the surface unit includes a control unit.

[00100] Another example method includes pumping fluid at a first velocity, pumping fluid at a second velocity and detecting a change between the first and second velocities using a sensor. The sensor includes a heater and a temperature sensor. The change in velocity is associated with data being transmitted. In some examples, the data being transmitted is transmitted from a downhole apparatus within a borehole to a surface unit. In some examples, the sensor is associated with the surface unit. In some examples, the data being transmitted is transmitted from a surface unit to a downhole apparatus. In some examples, the sensor is associated with the downhole apparatus. In some examples, the method also includes operating the downhole apparatus based on the change.

[00101] Although only a few example 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. Accordingly, 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, paragraph 6 for any limitations of any of the claims herein, except for those in which the claim expressly uses the words ‘means for’ together with an associated function.

[00102] The Abstract at the end of this disclosure is provided to comply with 37 C.F.R. §1.72(b) to allow the reader to quickly ascertain the nature of the technical disclosure. It is submitted with the understanding that it will not be used to interpret or limit the scope or meaning of the claims.

WHAT IS CLAIMED IS:

1. A method, comprising:

placing a sensor including a heater and a temperature sensor in a conduit;

sending a signal to the sensor by changing a velocity of a fluid traversing the conduit;

detecting a change in the velocity of the fluid with the sensor; and

operating an apparatus based on the change in velocity.

2. The method of claim 1, wherein operating the apparatus comprises activating a downhole apparatus.

3. The method of claim 1, wherein the fluid is wellbore fluid pumped by a surface pump.

4. The method of claim 1, wherein the sensor is positioned adjacent an interior surface of the apparatus.

5. The method of claim 1, wherein the sensor is positioned adjacent an exterior surface of the apparatus.

6. The method of claim 1, wherein sending the signal to the apparatus comprises sending a signal from a surface unit to a downhole apparatus.

7. A method, comprising:

transmitting a signal between a downhole tool and a surface unit by changing a velocity of a fluid traversing a wellbore; and

detecting a change in the velocity of the fluid with a sensor having a heater and a temperature sensor.

8. The method of claim 7, wherein the signal is associated with a measurement obtained downhole.

9. The method of claim 7, wherein the downhole apparatus comprises the sensor.

10. The method of claim 9, further comprising operating the downhole apparatus based on the signal.

11. The method of claim 9, wherein the sensor is positioned adjacent an interior surface of the downhole apparatus.

12. The method of claim 9, wherein the sensor is positioned adjacent an exterior surface of the downhole tool.

13. The method of claim 7, wherein the sensor is coupled to a pipe proximate the surface unit.

14. The method of claim 7, wherein the downhole apparatus comprises a logging tool.

15. The method of claim 7, wherein transmitting the signal comprises transmitting the signal from the surface unit to the downhole apparatus.

16. The method of claim 17, wherein the surface unit comprises a control unit.

17. A method, comprising:

pumping fluid at a first velocity;

pumping fluid at a second velocity; and

detecting a change between the first and second velocities using a sensor, the sensor comprising a heater and a temperature sensor, the change in velocity associated with data being transmitted.

18. The method of claim 17, wherein the data being transmitted is transmitted from a downhole apparatus within a borehole to a surface unit, and wherein the sensor is associated with the surface unit.

19. The method of claim 17, wherein the data being transmitted is transmitted from a surface unit to a downhole apparatus, and wherein the sensor is associated with the downhole apparatus.

20. The method of claim 19, further comprising operating the downhole apparatus based on the change.

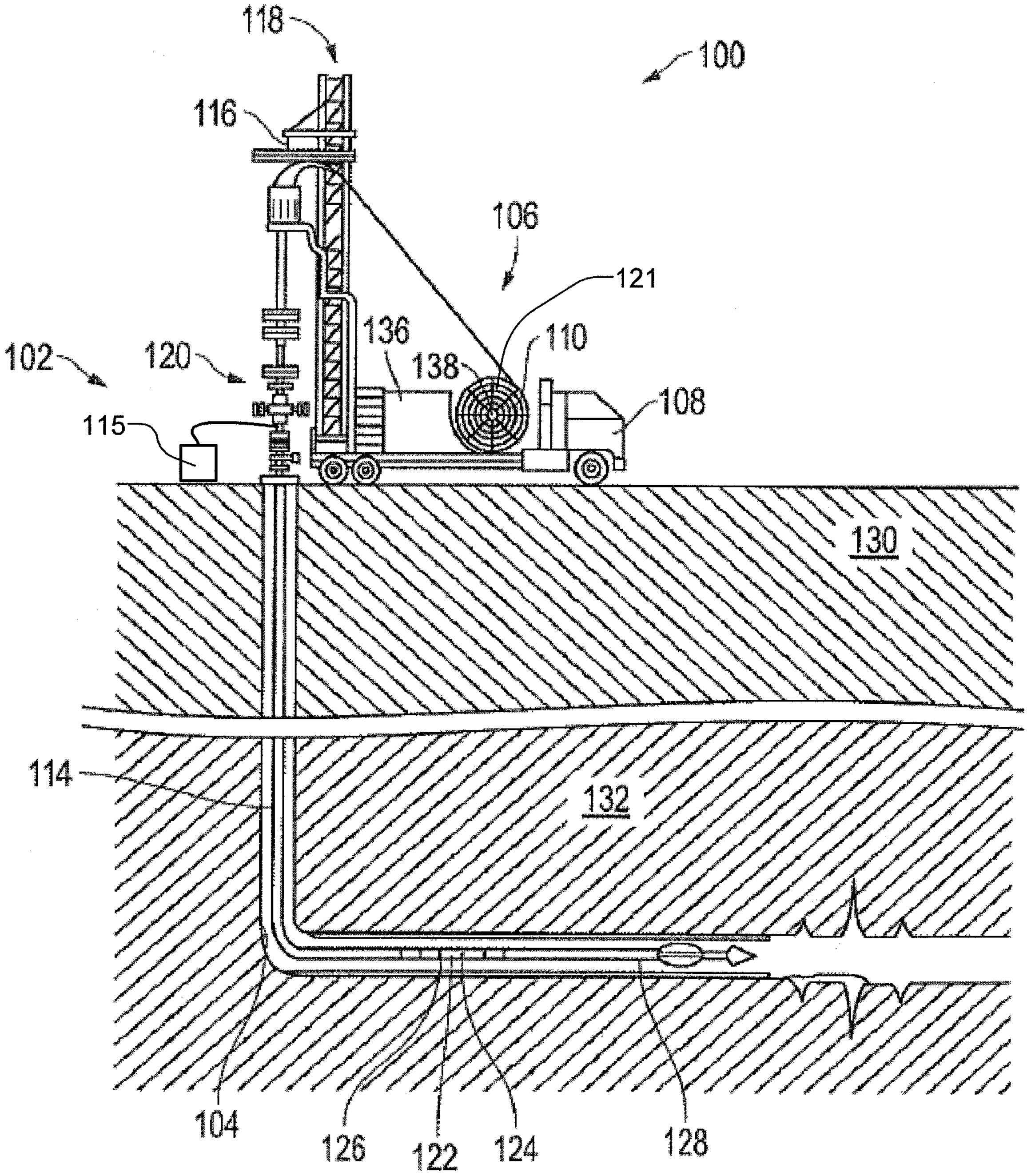
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FIG. 1A

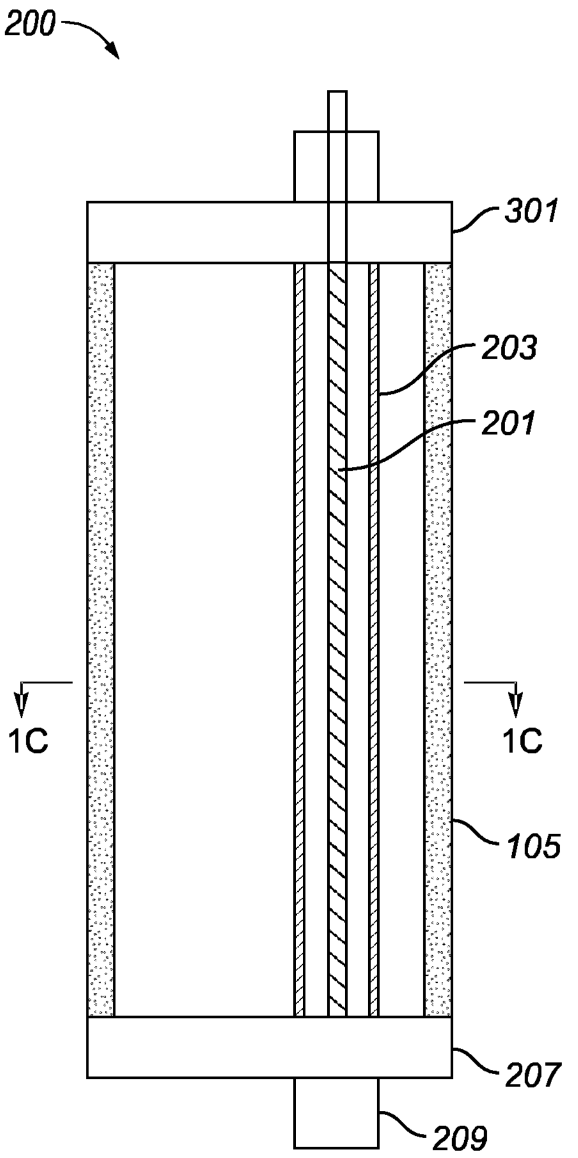

FIG. 1B

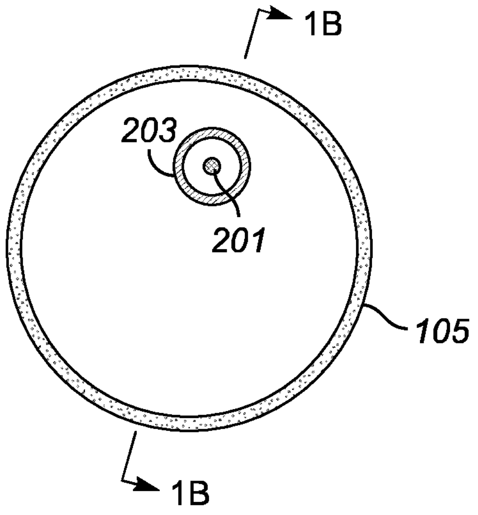

FIG. 1C

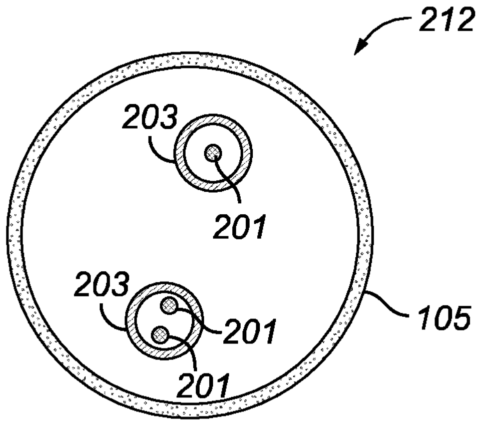

FIG. 1D

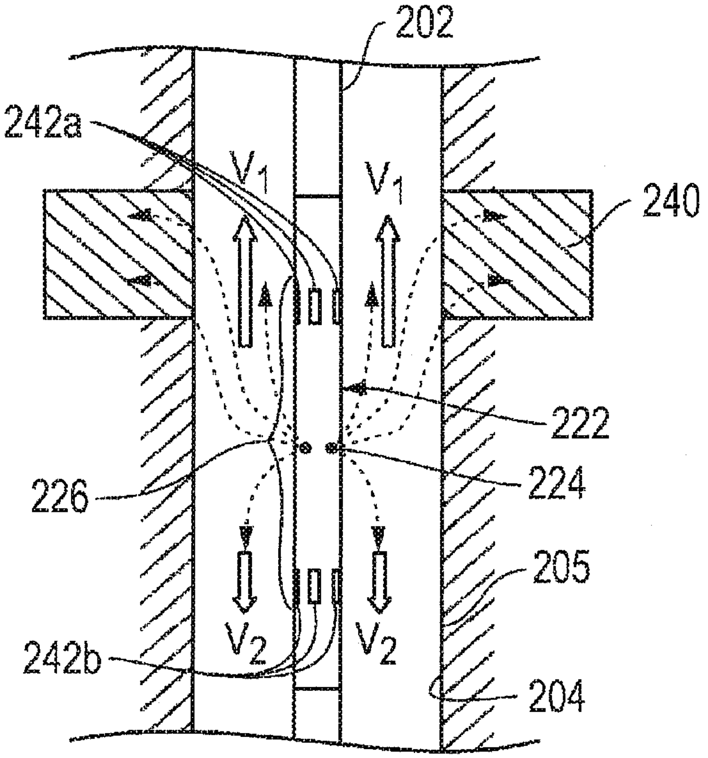

FIG. 2A

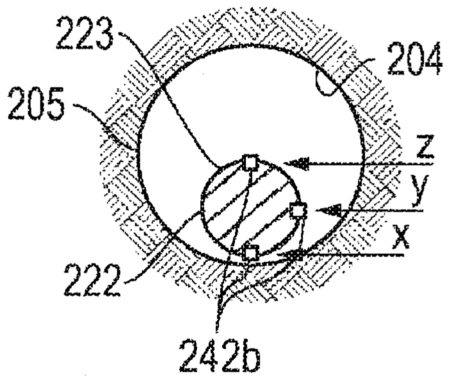

FIG. 2B

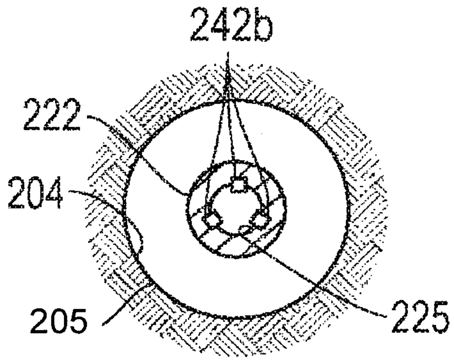

FIG. 2C

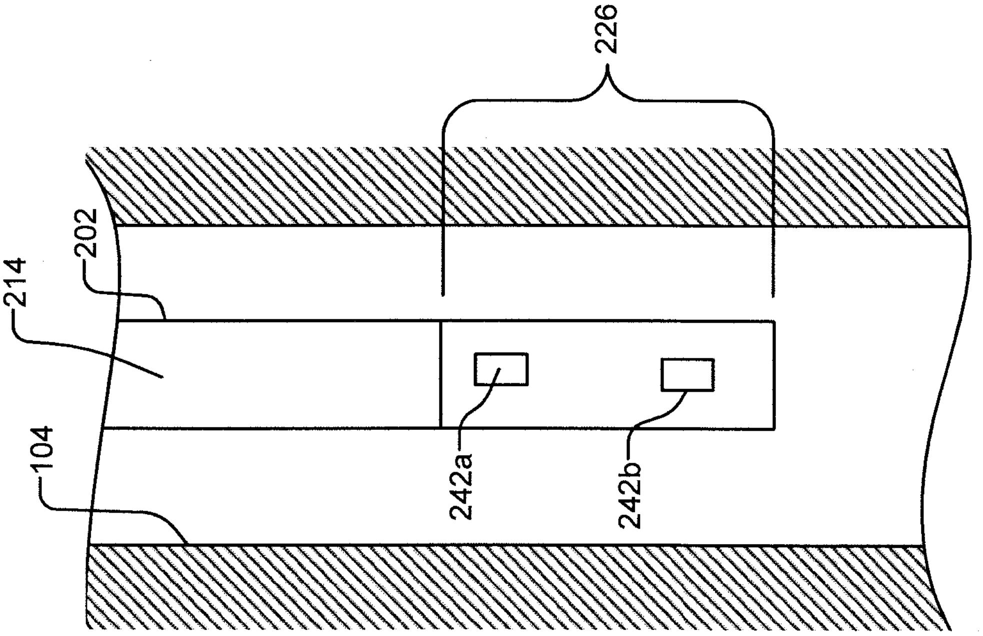
226
214
202
104
242a
242b

FIG. 2D

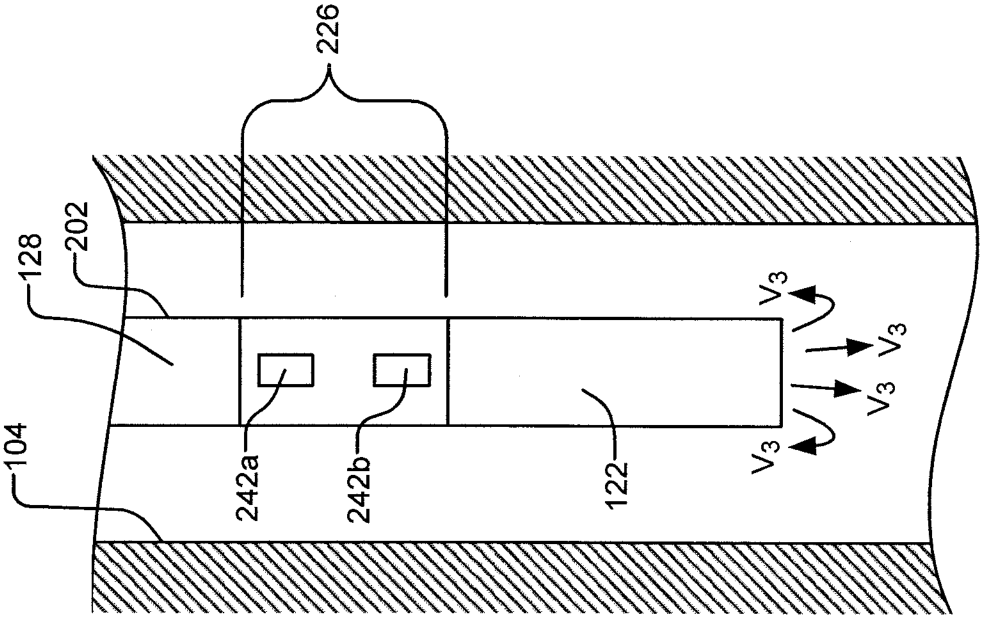
226
128
202
104
242a
242b
122
V_3
V_3
V_3
V_3

FIG. 2E

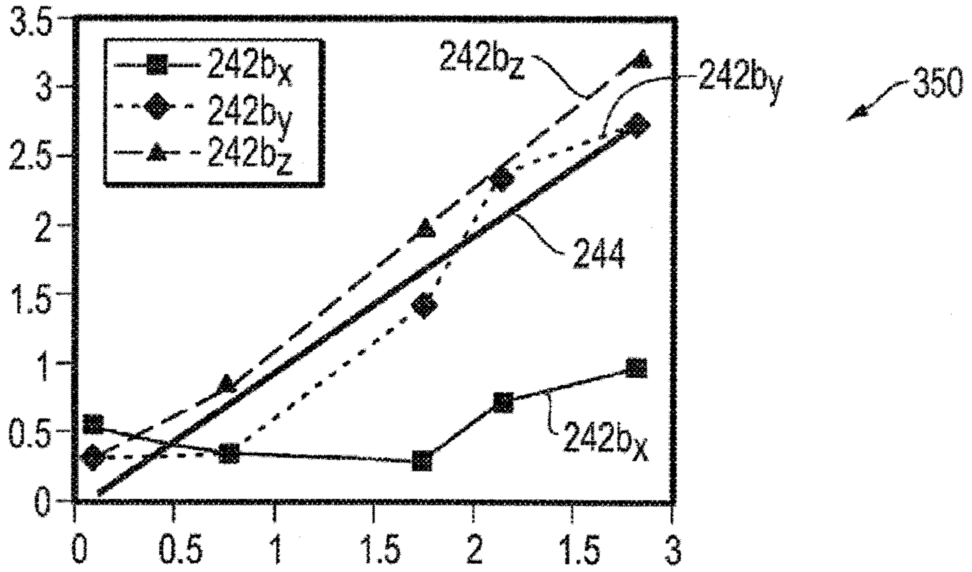
242bx
242by
242bz
242bz
242by
350
244
242bx
3.5
3
2.5
2
1.5
1
0.5
0
0
0.5
1
1.5
2
1.5
3

FIG. 3

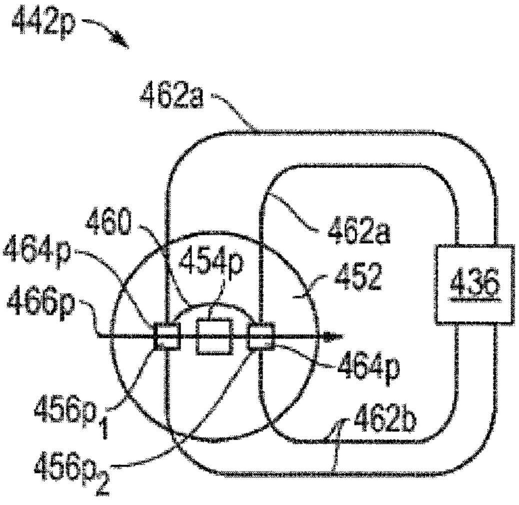

FIG. 4A

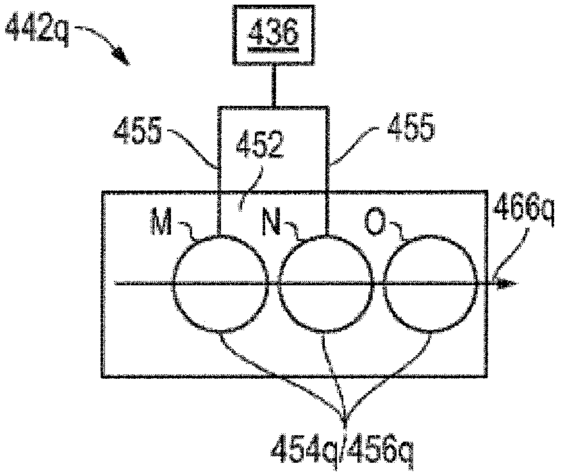

FIG. 4B

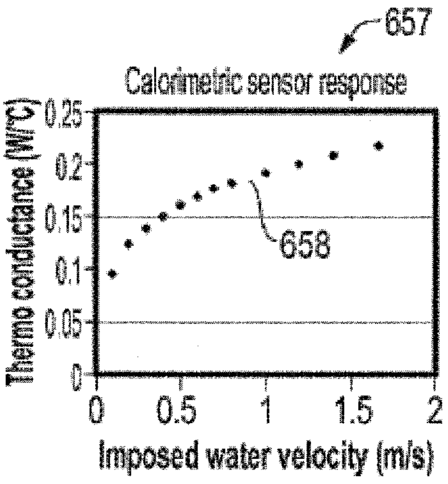

FIG. 5A

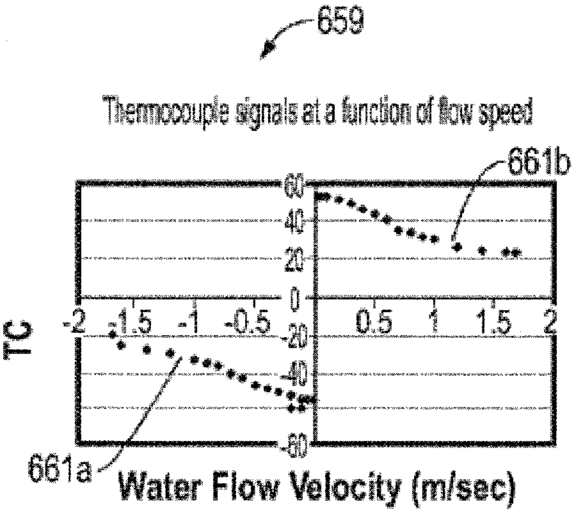

FIG. 5B

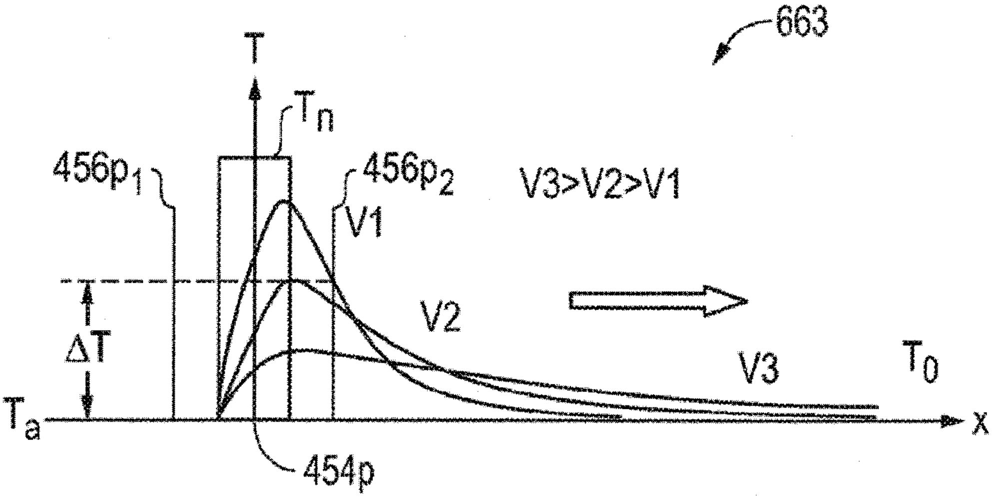
663
T
Tn
456p1
456p2
V3>V2>V1
V1
V2
V3
ΔT
Ta
T0
x
454p

FIG. 6

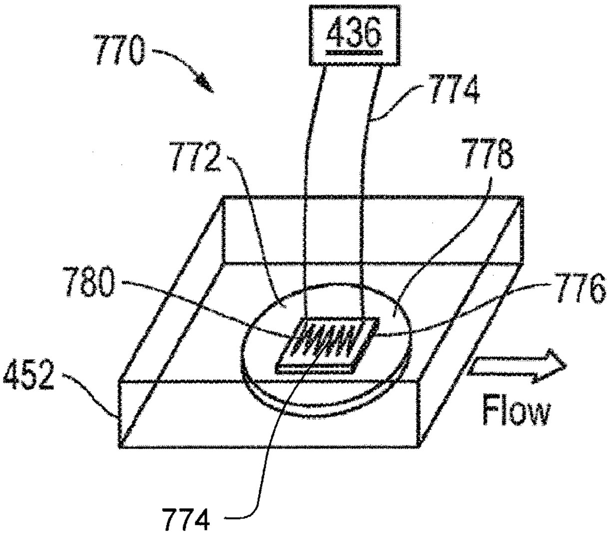
436
770
774
772
778
780
776
452
Flow
774

FIG. 7

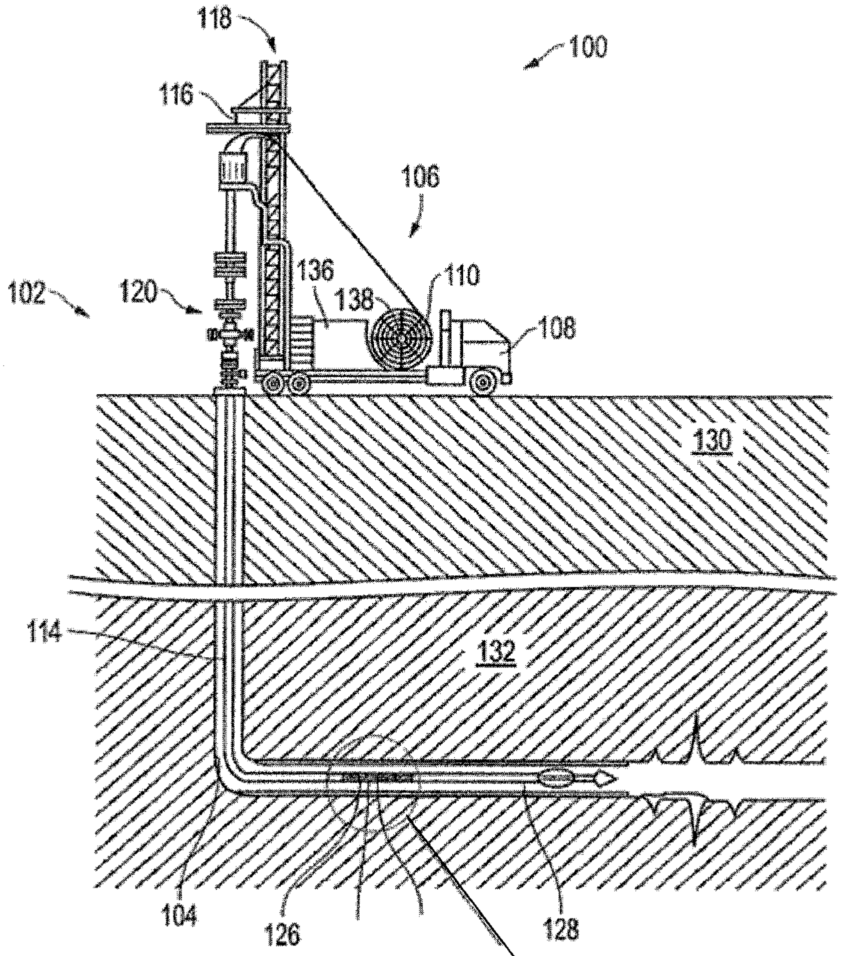
118
100
116
106
136
110
138
102
120
108
130
132
114
104
126
128

FIG. 8

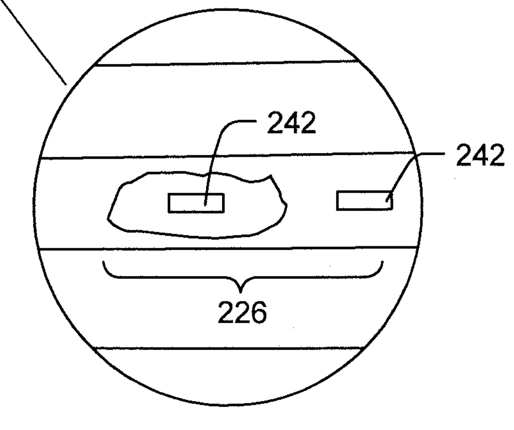
242
242
226

FIG. 8A

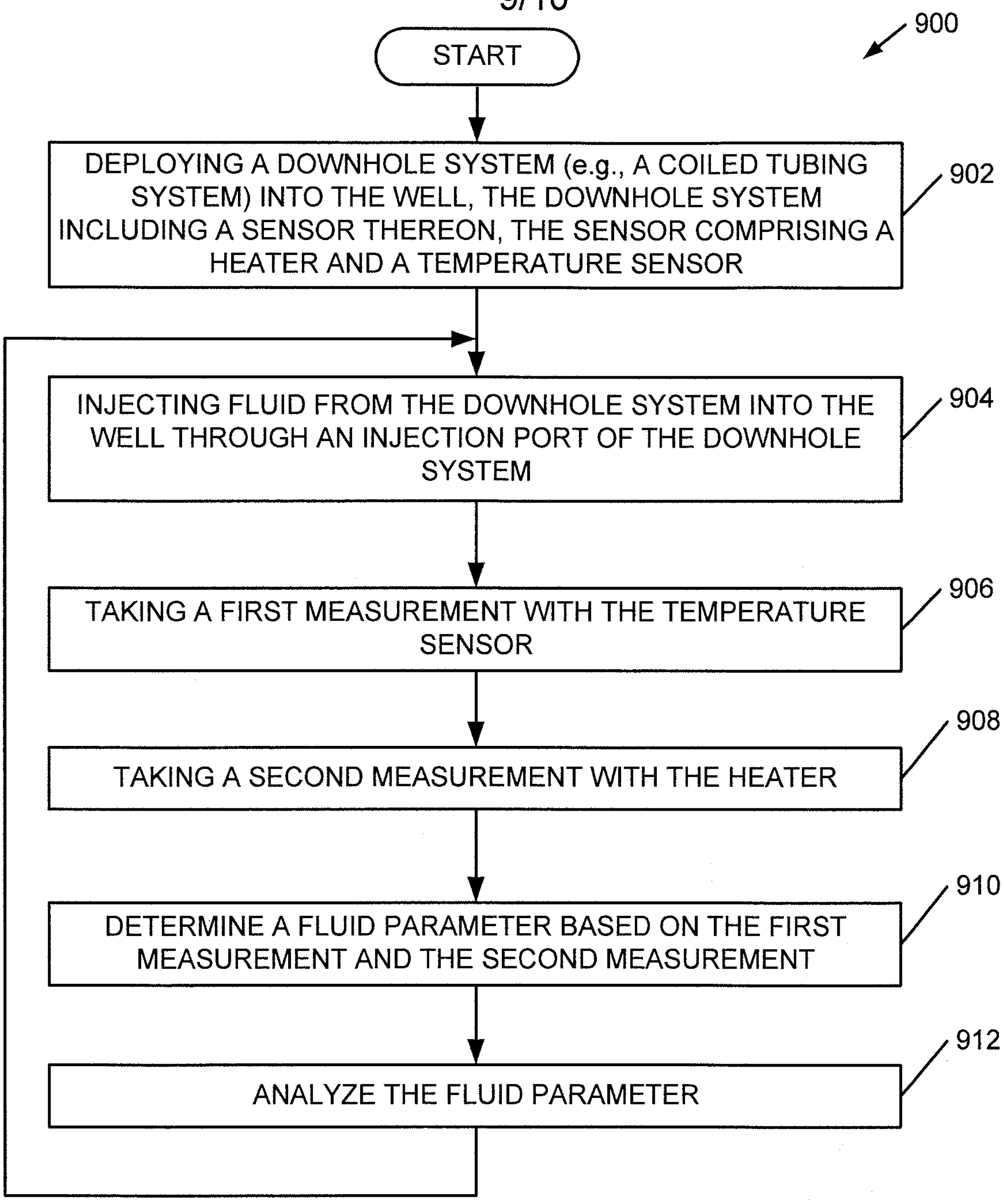
900
START
DEPLOYING A DOWNHOLE SYSTEM (e.g., A COILED TUBING SYSTEM) INTO THE WELL, THE DOWNHOLE SYSTEM INCLUDING A SENSOR THEREON, THE SENSOR COMPRISING A HEATER AND A TEMPERATURE SENSOR
902
INJECTING FLUID FROM THE DOWNHOLE SYSTEM INTO THE WELL THROUGH AN INJECTION PORT OF THE DOWNHOLE SYSTEM
904
TAKING A FIRST MEASUREMENT WITH THE TEMPERATURE SENSOR
906
TAKING A SECOND MEASUREMENT WITH THE HEATER
908
DETERMINE A FLUID PARAMETER BASED ON THE FIRST MEASUREMENT AND THE SECOND MEASUREMENT
910
ANALYZE THE FLUID PARAMETER
912

FIG. 9

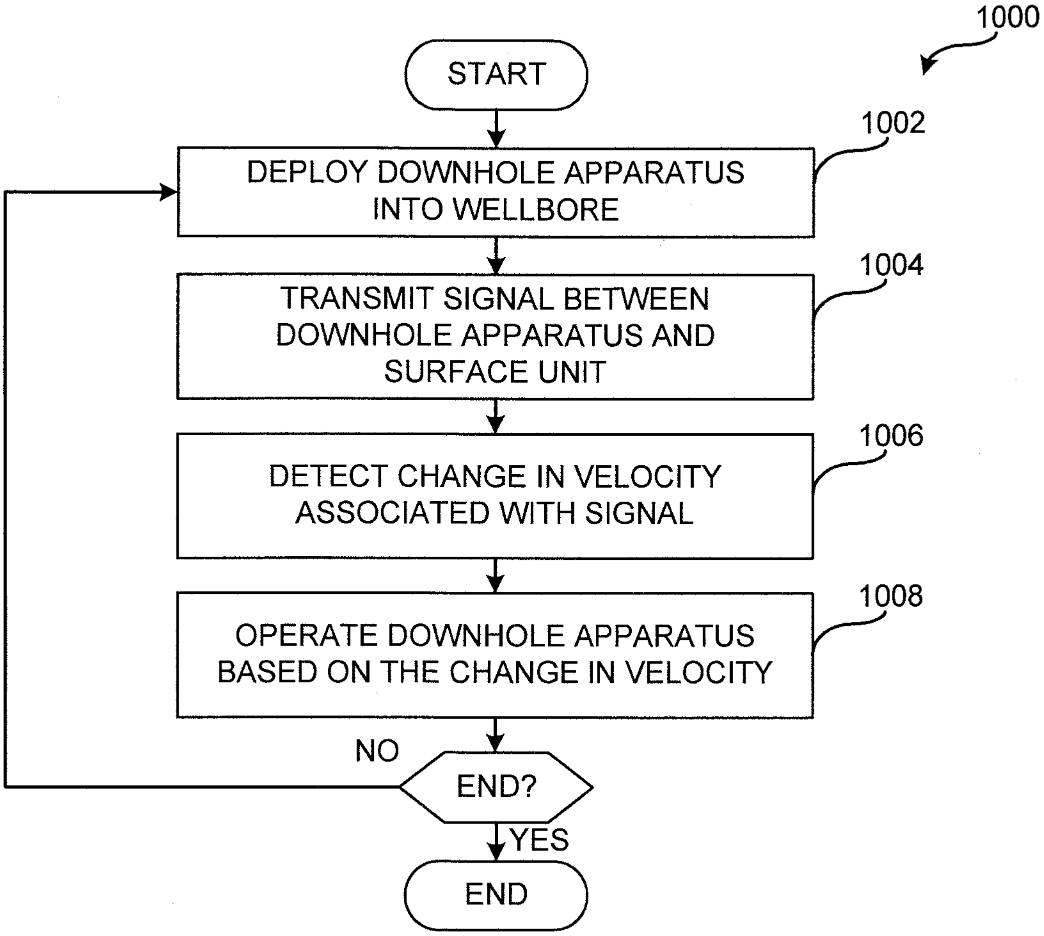
1000
START
1002
DEPLOY DOWNHOLE APPARATUS INTO WELLBORE
1004
TRANSMIT SIGNAL BETWEEN DOWNHOLE APPARATUS AND SURFACE UNIT
1006
DETECT CHANGE IN VELOCITY ASSOCIATED WITH SIGNAL
1008
OPERATE DOWNHOLE APPARATUS BASED ON THE CHANGE IN VELOCITY
NO
END?
YES
END

FIG. 10