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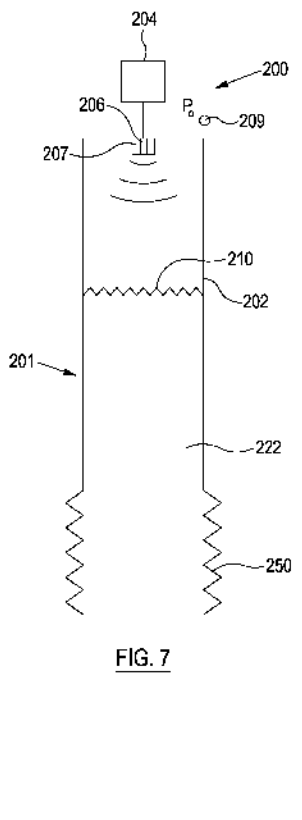

FIG. 7

(57) Abstract: The temperature in a containment region of a structure, e.g. a well, which comprises at least one tubular, e.g. casing and/or tubing, the containment region containing gas, can be determined in various methods, apparatus, and computer device. In various embodiments, an acoustic pulse is produced and at least one acoustic wave travels in the containment region between reference locations in response to the generated pulse; at least one sensor is used to detect the acoustic wave; at least one travel time of the acoustic wave between the reference locations is determined; at least one acoustic velocity for an interval based on the travel time taken between the reference locations is obtained; and the acoustic velocity and an equation of state model is used to determine the temperature.

WO 2020/226509 A1

DETERMINATION OF TEMPERATURE AND TEMPERATURE PROFILE IN PIPELINE OR A WELLBORE

Field of invention

The present invention relates in particular to the determination of temperature in structures that comprise tubulars, such as horizontal, deviated or vertical sections of pipe of pipelines or wellbores, and which may contain gas in a containment region of such a structure.

Background

Structures such as pipelines or wells comprising wellbore tubulars can contain fluids comprising gas in a containment region of the structure. Wellbore tubulars typically penetrate deep into the Earth's surface, and subsurface fluids, e.g. hydrocarbon liquids and/or gas may accumulate within the wellbore. In various contexts, for instance, it is desirable to know the temperature in the containment region, e.g. a horizontal, vertical or deviated section of tubular. Temperature and pressure are key parameters for understanding the conditions of the well and reservoir.

The fluids in a wellbore stratify with lighter fluids such as gas overlying heavier fluids such as liquids. This is typically the case in wellbores in the oil and gas exploration and production industry. In such cases, the wellbore may extend from the surface and penetrate a target oil and gas reservoir several kilometres below the surface.

At the location of a hydrocarbon reservoir, hydrocarbon fluids e.g. natural oil and gas, may enter from the formation into the wellbore. In addition, water in the formation may enter the wellbore. The natural hydrostatic pressure can lead to pressures and temperatures at the depth of the reservoir formation that are significantly higher than at the surface. As a result, fluids in the formation may enter the wellbore and travel toward the lower pressure region of the surface. In an oil and gas wellbore, and in particular in a wellbore which is shut in at surface, fluid components tend to stratify and occupy the wellbore according to the prevailing pressure(-depth) gradient, temperature(-depth) gradient and the composition of the fluid components. Normally, water is succeeded uphole by oil, and then gas.

In a traditional prior art method, temperature is measured in a pipeline or wellbore by installing temperature instruments. Should such instruments fail it is in many cases difficult or impossible to replace the instruments, especially if the temperature instrument is part of a wellbore completion.

With reference to Figure 1, another known method is to monitor temperature in a wellbore 1 by lowering a temperature measurement sensor 2 on a wireline 3, so as to read off the actual temperature at different depths in the wellbore. The wellbore 1 contains gas 5 and liquid 6, and the wireline 4 can be spooled in or out from a drum 4 at a surface facility. Such a method can be inconvenient and time consuming, as it requires intervention by wireline or slickline into the wellbore which leads to significant costs. Intervention by wireline/slickline is also only possible in the tubular, and not in the annular space of the wellbore (surrounding the tubular).

Summary of invention

An aim of the invention is to obviate or at least mitigate one or more drawbacks associated with prior techniques.

According to a first aspect of the invention, there is provided a method of determining at least one temperature in a containment region of a structure which comprises at least one tubular, the containment region containing gas, the method comprising the steps of: producing an acoustic pulse, at least one acoustic wave travelling in the containment region between reference locations in response to the generated pulse; using at least one sensor to detect the acoustic wave; determining at least one travel time of the acoustic wave between the reference locations; obtaining at least one acoustic velocity for an interval based on the travel time taken between the reference locations; and using the acoustic velocity and an equation of state model to determine the temperature.

The equation of state model may typically have interrelated pressure, temperature, gas composition, acoustic velocity, and/or gas density components. The acoustic velocity may accordingly be related to the temperature component through the model. The equation of state model may be as defined anywhere else herein.

The method may further comprise computing, calculating, or otherwise determining the temperature from the obtained acoustic velocity, based on or using the equation of state model.

The method may further comprise providing a pressure of the gas, and using the pressure and the acoustic velocity to determine the temperature.

The tubular may comprise at least one tubular of a wellbore extending into the Earth from surface and the pressure may comprise a pressure P_0 at or near surface, and the method may include measuring the pressure P_0 if the pressure is not known. The tubular may comprise at least one tubular of a wellbore extending into the Earth from surface and the pressure is based on a pressure P_0 at or near surface, and an estimated density of the gas, and the method may include measuring the pressure P_0.

The method may further comprise defining a composition of the gas, wherein the step of using the acoustic velocity and the equation of state model to determine the temperature may be performed based on the defined composition of the gas. The composition may be obtained using a gas chromatograph or a similar instrument

The method may further comprise determining various physical properties of the gas based on the determined temperature combined with known or measured pressure and gas composition.

The structure may comprise inner and outer tubulars, e.g. casings, of a well, the inner tubular being arranged inside the outer tubular, and the containment region may comprise an annulus between an inner tubular and the outer tubular.

A plurality of intervals between reference points may be defined, and the method may include: determining acoustic velocities for the respective intervals based on the times of travel of the acoustic wave; and determining temperatures for the respective intervals using the acoustic velocities and the equation of state model. The method may further comprise using the temperatures to obtain a profile of the temperature versus distance along the section of pipe.

The tubular may be or comprise a deviated, vertical, or horizontal tubular or tubular section. The tubular may correspondingly be located in a deviated, vertical, or horizontal section of a wellbore. A wellbore annulus may surround the tubular. The tubulars may be arranged one within another, whereby an annulus may be defined between an outer surface of an inner tubular and an inner surface of an outer tubular. The annulus may provide the containment region.

According to a second aspect of the invention, there is provided a method of performing an inflow test in a well, using the temperature determined by performing the method according to the first aspect of the invention to determine a rate of flow into the containment region of the structure.

According to a third aspect of the invention, there is provided method of investigating and quantifying leakage rate of a fluid between a first pipe and a second pipe, wherein the first pipe is surrounded by at least a portion of the second pipe, where the pipes are arranged in a well in a ground, wherein the temperature of gas from an annulus surrounding a leakage site in the first pipe is determined by the method of the first aspect of the invention.

According to a fourth aspect of the invention, there is provided apparatus for performing the method of any of the first to third aspects of the invention.

According to a fifth aspect of the invention, there is provided a computer program for computing the temperature from the obtained acoustic velocity in the method of the first to third aspects of the invention.

According to a sixth aspect of the invention, there is provided a computer device comprising a processor which when executing the computer program of the fifth aspect of the invention is caused to determine the temperature from the obtained acoustic velocity.

According to a seventh aspect of the invention, there is provided a data carrier, data transmission medium, or data signal carrying any one or more of: the computer program of the fifth aspect of the invention; the acoustic velocity data or travel time data obtained in performing the method of any of the first to third aspects of the invention; and the determined temperature data obtained using the travel time data or the acoustic velocity data from performing the method of any of the first to third aspects of the invention.

According to an eighth aspect of the invention, there is provided apparatus for determining at least one temperature in fluid comprising gas in a containment region of a structure which comprises at least one tubular, the apparatus comprising: at least one acoustic transmitter for producing an acoustic pulse to generate at least one acoustic wave to travel in the containment region between reference locations; at least one sensor to detect the acoustic wave and determine the travel time of the acoustic wave between the reference locations; and at least one determiner for determining the acoustic velocity from the travel time and using the acoustic velocity and an equation of state model to determine the temperature.

The sensor may comprise a microphone. The sensor may be arranged to communicate data from the sensor to the determiner. The apparatus may further comprise at least one pressure sensor arranged for detecting the pressure in the containment region.

Various further features of the various aspects of the invention may be defined in the claims appended hereto or elsewhere herein. The various aspects of the invention may have further features as defined in relation any other aspect of the invention wherever described herein.

By way of the invention, temperature may advantageously be determined and monitored in pipelines and wellbores, in cases where it may not previously have been possible or feasible using conventional temperature instruments.

Various further advantages of the invention will be apparent from the following description and elsewhere throughout.

<u>Drawings and description</u>

There will now be described, by way of example only, embodiments of the invention, with reference to the accompanying drawings, of which:

Figure 1	is a schematic representation according to prior art of a wellbore in which a temperature measurement tool is being run on a wireline;
Figure 2	is a schematic representation of apparatus for determining temperature in a horizontal pipe according to an embodiment of the invention;
Figure 3	is a schematic representation of apparatus for determining temperature in a vertical or deviated section of pipe of a wellbore according to another embodiment of the invention;

Figure 4 is a schematic representation of apparatus for determining temperature in a vertical or deviated section of pipe of a wellbore according to yet another embodiment of the invention;

Figure 5 is a schematic representation of apparatus for determining a temperature profile with distance in a horizontal pipe according to an embodiment of the invention;

Figure 6 is a schematic representation of apparatus for determining a temperature profile with depth in a vertical or deviated section of pipe of a wellbore according to yet another embodiment of the invention;

Figure 7 is a schematic representation of apparatus for determining temperature in a wellbore containing gas and liquid according to another embodiment of the invention; and

Figure 8 is a schematic representation of apparatus for determining temperature in an annulus of a wellbore.

Parameters of pressure, temperature, density, and composition of a gas contained in a defined space, such as in a section of a wellbore, are interrelated through an equation of state. The literature describes well known equations of state containing specific mathematical relationships among the parameters of pressure, temperature, density, and composition of a gas, for approximating or modelling the condition of a gas-containing region. A selected parameter can be determined from knowledge of the other parameters using such relationships. Equations of state have been developed for fluids in wellbores such as gases and mixtures of gas components contained in pipes in a wellbore.

In example embodiments of the present invention, the acoustic velocity through the gas is measured and used for determining the temperature. From the determined temperature, other equation of state parameters can be determined using known equation of state relationships. The acoustic velocity can be determined based on the formula:

$$AV_{AVG} = f(P_{AVG}, T_{AVG}, Comp) \qquad \text{[Equation 1a]}$$

where AV_{AVG} is the average acoustic velocity, P_{AVG} is the average pressure, T_{AVG} is the average temperature, and *Comp* is the composition of the gas.

In practice, the acoustic velocity can be determined from the speed of sound relation such as set out in equation 3.1 of the article of Smith, J. P. and Clancy, J. with title "*Understanding AGA Report No. 10 Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases*", 12 January 2011, published by the American School of Gas Measurement Technology (ASGMT). This is based on the ideal gas equation and adiabatic conditions. The American Gas Association's AGA Report No. 10 has the title "*Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases*", is published January 2003, and provides information for computation of sound speed in natural gas and other related hydrocarbon gases. The speed of sound relation is as follows:

$$W = \left[\left(\frac{C_p}{C_v}\right)\left(\frac{RT}{M_r}\right)\left(Z + \rho\frac{\partial Z}{\partial \rho}\right)_T\right]^{0.5} \qquad \text{[Equation 1b]}$$

where

C_p and C_v are the constant pressure and constant volume heat capacities of the gas;

R is the ideal gas constant;

M_r is the molar mass;

Z is compressibility;

ρ is density; and

T is temperature.

This equation is an equation of state model relating the acoustic velocity (through the speed of sound W) to the temperature, density, pressure, and composition (through compressibility and molar mass) of the gas. These parameters may be computed through the procedures as set out in the equations 3.1 to 3.17 and related text of the abovementioned article of Smith and Clancy.

The equation of state model can in other variants be in the form of a database or table of precalculated values from the speed of sound relation, e.g. different values of acoustic velocity for different pressure, temperatures, and composition.

In various examples that follow herein, acoustic measurements are performed by sending an acoustic pulse (positive or negative) into a section of gas-filled or partially gas-filled pipe. The acoustic pulse reflects back from the end of the gas filled section after a period of time. If the length of the gas filled section is known, the average acoustic velocity can be determined by measuring the round-trip travel time for the reflected pulse.

Based the formula of Equation 1, it is then possible to determine the average temperature from the determined velocity in a section of pipe if the average pressure and composition is known or estimated. The relationship of dependence between the acoustic velocity and the pressure, temperature and composition of the gas in an equation of state model for wellbore gas contained in a pipe is well known.

Once the average pressure, temperature and gas composition has been determined from the acoustic velocity, the equation of state model can also be used to determine other physical properties of the gas, such as density, pressure gradient, temperature gradient, and so forth.

EXAMPLES

Various embodiments are described in the following examples.

Example 1

With reference to Figure 2, apparatus 100 for determining temperature in a horizontal section of pipe 102 is generally depicted. The apparatus 100 includes an acoustic instrument 104 which includes a transmitter 106 that transmits an acoustic pulse into the pipe 102. The acoustic instrument 104 further includes an acoustic sensor 107. Acoustic waves from the transmitted pulse are reflected from an end 110 of the pipe 102 and propagate back along the pipe 102. The acoustic sensor 107 responds to the reflected waves received at the sensor and the time of arrival of the reflected waves are recorded. From this, the two-way round-trip travel time of the reflected waves over the length L of the section of pipe is obtained.

The acoustic sensor 107 is for example a microphone or a pressure sensitive sensor or transducer. The transmitter 106 can be a sound generator.

The acoustic instrument 104 or apparatus 100 also includes a computer device 112. The computer device 112 includes memory 113 for storing a computer program and data. The computer device 112 may further include a microprocessor 114 for executing at least one computer program. The computer program when executed can cause the computer device 112 to output an instruction to the transmitter 106 to transmit the pulse into the pipe 102. A computer program can also be executed to process and/or analyse response data from the sensor 107 to determine the travel time and acoustic velocity.

In this example, the horizontal section of pipe 102 is gas filled or partially gas filled with the end 110 of the section 102 comprising an acoustic reflector. The length L is known e.g. from previous knowledge about the pipe, e.g. by knowing the location of the reflector. The pressure P in the pipe is measured, e.g. using a pressure sensor exposed to the interior of the pipe. Since the pipe section 102 is horizontal it can be appreciated that there is no hydrostatic variation in the section, such that the pressure P applies uniformly within the pipe section 102. The composition of the gas may be known or can be measured on-site using a gas analyser.

The average gas temperature T_{AVG} and density in the section of pipe 102 can then be determined according to the following:

$$T_{AVG} = f(P, AV_{AVG}, Comp) \qquad \text{[Equation 2]}$$

When the average gas temperature T_{AVG} is determined, the physical properties such as the density or gravity of the gas can be determined using the following equation:

$$Gas\ Density\ /Gravity = f(P, T_{AVG}, Comp) \qquad \text{[Equation 3]}$$

where P is pressure in the pipe, AV_{AVG} is the average acoustic velocity to the reflector and *Comp* is the composition of the gas.

The equations can be implemented on the computer device. For example, the computer program may comprise machine readable instructions for calculating the acoustic velocity, temperature and density according to Equations 2 and 3 based on input data. Data from the acoustic instrument e.g. arrival times of reflected waves, provide input to the calculation. When the program is executed by the processor, the computer is caused to perform the calculations of temperature and/or density.

<u>Example 2</u>

Referring to Figure 5, this example differs from Example 1 in that the section of pipe 102 additionally includes further reflection locations 120a-120d. Thus, acoustic waves from the transmitter are also reflected from each of the reflection locations 120a-120d. Using the same principle as for the reflected waves of Example 1, the average acoustic velocity to each reflector 120a-120d is determined by using the sensor 107 and measuring the round-trip travel time for the acoustic pulse to reflect back from each reflector.

The reflection locations 120a-120d are locations along the length of the pipe 102 where the cross-sectional diameter changes from one diameter to another. The distances to the changes in cross sectional diameter are known from a pipe schematic.

By determining T_{AVG} to each reflection point using Equation 2, the temperature profile, i.e. the temperature versus distance along the pipe, in the pipe can be obtained. Similarly, the gas density profile in the pipe can be obtained using Equation 3.

Example 3

Referring to Figure 3, a vertical section of pipe 102, is gas filled or partially gas filled with the end 110 of the section 102 comprising an acoustic reflector. The apparatus 100 operates as explained above in relation to Example 1. The average acoustic velocity is obtained by measuring the round-trip travel time over the distance L for reflected acoustic waves to reflect back from the end 110.

The pressure in the pipe is measured to give an average pressure P_{AVG} for the length L. The composition of the gas is known or can be measured onsite using a gas analyser.

The average gas temperature and density in the section of pipe 102 is then determined according to the following:

$$T_{AVG} = f(P_{AVG}, AV_{AVG}, Comp) \qquad \text{[Equation 4]}$$

When the average gas temperature T_{AVG} is determined, the physical properties such as the density or gravity of the gas can be determined using the following equation:

$$Gas\ Density/Gravity = f(P_{AVG}, T_{AVG}, Comp) \qquad \text{[Equation 5]}$$

where P_{AVG} is the average pressure in the pipe section, AV_{AVG} is the average acoustic velocity to the reflection point and *Comp* is the composition of the gas.

In variants of this example, the pipe 102 can have multiple reflection locations such as locations 120a-120d in Example 2 which are locations along the length of the pipe where the cross-sectional diameter changes from one diameter to another. In such variants, the distance to the changes in cross sectional diameter is known from a pipe schematic. The average pressure down to each reflection location or in the interval between successive reflection locations is measured, e.g. using a pressure sensor. As this is a vertical pipe and if the gas filled column stretches a significant vertical distance into the Earth, pressure and temperature conditions can vary significantly with depth e.g. due to geothermal gradient and hydrostatic effects. The acoustic velocity down to each reflection point is determined be measuring the round-trip travel time for the acoustic pulse to reflect back from each reflection point. The temperature and density can then be obtained from the Equations 4 and 5 for successive intervals along the pipe. By determining T_{AVG} down to each reflection point, the temperature profile in the pipe can be determined. Similarly, the gas density profile in the pipe can be determined.

Example 4

Referring to Figures 4 and 6, a vertical section of pipe which is gas filled or partially gas filled, the average acoustic velocity AV_{AVG} in the gas filled section of the pipe is measured. The composition of the gas may be known or can be measured using a gas analyser.

The apparatus 100 in this case further includes a pressure gauge 109. The surface pressure P_0 is measured using the pressure gauge 109.

The measured acoustic velocity AV_{AVG}, the surface pressure P_0, and gas composition *Comp* are first used to estimate the average temperature of the gas column based on the following:

$$T_{AVG1} = f(P_0, AV_{AVG}, Comp) \qquad \text{[Equation 6]}$$

$$Gas\ Density\ (D_1) = f(P_0, T_{AVG1}, Comp) \qquad \text{[Equation 7]}$$

However, assuming a simple surface pressure P_0 results only in a rough determination of the temperature and density. An improved, estimated average pressure to the reflector is calculated using:

$$P_{AVG1} = P_0 + D_1 * g * TVD / 2 \qquad \text{[Equation 8]}$$

where g is the gravitational constant and TVD is vertical depth to the reflector from the microphone.

The measured acoustic velocity AV_{AVG}, estimated average pressure P_{AVG1}, and gas composition *Comp* are then used to estimate, and improve the estimation of, the average temperature of the gas column, as follows:

$$T_{AVG2} = f(P_{AVG1}, AV, Comp) \qquad \text{[Equation 9]}$$

$$Gas\ Density\ (D_2) = f(P_{AVG1}, T_{AVG2}, Comp) \qquad \text{[Equation 10]}$$

This iteration continues until the average temperature does not change anymore. At this point the determined average pressure and temperature will match the measured acoustic velocity.

The next “iteration” would look like this:

$$P_{AVG2} = P_0 + D_2 * g * TVD/2 \qquad \text{[Equation 11]}$$

$$T_{AVG3} = f(P_{AVG2}, AV, Comp) \qquad \text{[Equation 12]}$$

$$Gas\ Density\ (D_2) = f(P_{AVG2}, T_{AVG3}, Comp) \qquad \text{[Equation 13]}$$

As mentioned above, the equation of state model can in other variants be in the form of a database or table of precalculated values from the speed of sound relation, e.g. different values of acoustic velocity for different pressure, temperatures, and composition. Therefore, in some examples, the acoustic velocity can be determined based on the measurement of acoustic waves returned to the sensor as described above, and then the temperature associated with the acoustic velocity can be found from the model, e.g. by reading off the temperature from a database or look up table. In other variants, a theoretical value of the acoustic velocity can be calculated for a given, pressure, temperature, and composition e.g. based on the equations above. The actual measured acoustic velocity can then be compared with a theoretical calculated value, to obtain a temperature which produces a “high fit” match between the measured acoustic velocity and that predicted. To find the best match, the assumed or estimated pressure and composition parameters may be varied iteratively from an initial guess or estimate.

The determined temperature may be used in various ways. In the above examples, the temperature or profile of temperature with distance along the pipe is determined based on measured acoustic velocity to one or more reflectors. The average gas pressure P_{AVG} can then be determined using equation of state relations as follows:

$$P_{AVG} = f(T_{AVG}, AV, Comp) \qquad \text{[Equation 14]}$$

By obtaining determining P_{AVG} (and T_{AVG} based on AV) for each interval between reflectors the profile and variation of pressure along the pipe can be determined and plotted. By plotting the profile, the changes in pressure, temperature and density/gradient at each reference point can be visualised. In addition, the resulting parameters measured and calculated can be verified against data collected in other ways. For example, the plot produced can be used to identify any measurement/calculation which is not consistent with measurements of temperature and pressure made direct in the well. Measurements/calculations which does not give the expected result may indicate that the measurements should be repeated.

As indicated in Figure 7, a wellbore 201 is provided with apparatus 200 for determining the temperature in a section of pipe 201 of the wellbore that contains gas. The wellbore 201 penetrates into a hydrocarbon reservoir at 250 so as to allow communication of fluids from the reservoir into the wellbore 201. Corresponding features to those described in the examples above are referenced with the same numerals but incremented by one hundred. The wellbore 201 includes a lower section of pipe 222 which is liquid filled, e.g. with water and oil. The reflector at the lower end of the gas filled section is in this case the gas-liquid interface 210. The change in acoustic properties at the interface 210 leads to reflection of the acoustic waves transmitted into the pipe. The acoustic waves are typically transmitted from the acoustic instrument 204 via the wellhead and/or valve tree. The instrument 204 is arranged at the surface, e.g. on the rig or installation (not shown).

The gas filled section 202 can include further reflectors such as points of narrowing of the pipe in the wellbore as 120a-120d as described above. Such points of narrowing may be found for example at joints, sleeves, or collars between sections of pipe in the well. Other physical features or artefacts in the pipe extending through the wellbore can be utilised similarly as “reflectors” where these can produce an effect in the acoustic waves returning to the sensor 207 in response to the pulse transmission.

Although various examples above refer to a section of pipe in a wellbore, the same technique can be applied more generally in a well, for instance to fluid columns in the casing or tubing annuli of an oil and gas well, such as is described briefly now with reference additionally to Figure 8. In Figure 8, a central production tubing 433 is surrounded by a first casing 435. The first casing 435 is surrounded by a second casing 437, which in turn is surrounded by a third casing 439. The casings 435, 437, 439 comprise tubulars which are arranged at different heights relative to the production tubing and extend into the subsurface of the earth. An annulus A, the so-called “A-annulus”, is defined between the production tubing 433 and the first casing 435, an annulus B, the “B-annulus”, is defined between the first casing 435 and the second casing 437, and an annulus C, the “C-annulus” is defined between the second casing 437 and the third casing 439. A packer element 451 provides a barrier in a lower part of the A-annulus.

As can be appreciated, a fluid column is present in the A-annulus comprising liquid FL and gas FG. By leakage through the hole 432 through the wall of the first casing 435, fluid has entered into and accumulated in the B-annulus such as shown in Figure 8. The B-annulus acts in effect as a separation chamber for the various fluid phases. Accordingly, the B-annulus also fluid column comprising liquid FL and gas. The well 401 is provided with apparatus 400 for determining the temperature in the section of the B-annulus containing gas FG. Corresponding features to those described in the examples above are referenced with the same numerals but incremented by a multiple of one hundred. A lower section of the B-annulus is liquid filled with Liquid FL, e.g. water and oil. The reflector at the lower end of the gas filled section is in this case the gas-liquid interface 410. The change in acoustic properties at the interface 410 leads to reflection of the acoustic waves transmitted into the pipe, back to the sensor e.g. microphone 407.

In this particular example of Figure 8, a further measuring arrangement 420 includes a flow meter 464 and a pressure meter or gauge 466. The measuring arrangement is in fluid communication with the B-annulus through the fluid line 462. The pressure meter or gauge 466 can measure differential pressure between the A- and B-annuli by respective pressure sensors 465, 465'. The measuring arrangement 420, can be used to quantify the leakage rate, with the valve 469 being used to regulate the pressure differential between annuli constant. The patent publication WO2010/151144 describes a measurement arrangement generally of this kind for quantification of leakage using the pressure meter and flow meter. There is incorporated herein by reference the method and apparatus as set out in claims 1 and 7, or any other claims, in the patent publication WO2010/151144, wherein the temperature meter mentioned in that document may not be required, but wherein instead, a temperature may be determined by measuring the acoustic velocity AV for the gas column of the B-annulus. This can facilitate a more accurate determination of temperature and hence improve the leakage quantification.

In further variants, the determined temperature from acoustic measurements as explained above can be used in wellbore inflow tests, where the leakage rate of gas into the pressurised chamber is determined as pressure is bled off. The chamber may be an annulus such as the B-annulus in the example of Figure 8, and the acoustic velocity in the gas in the chamber is obtained by recording the arrival of acoustic waves returning from known reflection points therein. In such an inflow test, the following equation applies for the leak flow rate Qv after the pressure is bled down and monitored for subsequent build up due to leakage at times t_1 and t_2:

$$Q_v = \frac{MW}{\rho RT}\left[\frac{P_2V_2}{Z_2T_2} - \frac{P_1V_1}{Z_1T_1}\right] \qquad \text{[Equation 15]}$$

where

MW is molecular weight of the gas;
P_1 and P_2 is the pressure at time t_1 and t_2 respectively;
V_1 and V_2 is the volume of the chamber containing the gas at time t_1 and t_2;
T_1 and T_2 is the temperature at time t_1 and t_2;
Z_2 and Z_1 is the compressibility of the gas at time t_1 and t_2;
R is the Rankine constant; and
T is temperature.

The temperatures T1 and T2 are obtained from acoustic transmission and measurement of returning acoustic waves over time in the gas in corresponding manner to that described in the various examples above.

In prior art the temperature is typically not measured. However, the temperature parameter is an important parameter for an accurate and reliable determination of the leakage and/or leakage rate. In particular, the technique herein of making an acoustic velocity-based determination of the temperature can be beneficial in that it can provide a reliable average temperature for a large volume chamber of gas.

Various modifications and improvements may be made without departing from the scope of the invention herein described.

CLAIMS

1. A method of determining at least one temperature in a containment region of a structure which comprises at least one tubular, the containment region containing gas, the method comprising the steps of:

producing an acoustic pulse, at least one acoustic wave travelling in the containment region between reference locations in response to the generated pulse;

using at least one sensor to detect the acoustic wave;

determining at least one travel time of the acoustic wave between the reference locations;

obtaining at least one acoustic velocity for an interval based on the travel time taken between the reference locations; and

using the acoustic velocity and an equation of state model to determine the temperature.

2. A method as claimed in claim 1, wherein the equation of state model has interrelated pressure, temperature, gas composition, and gas density components.

3. A method as claimed in any preceding claim, which further comprises providing a pressure of the gas, and using the pressure and the acoustic velocity to determine the temperature.

4. A method as claimed in claim 3, wherein the tubular comprises at least one tubular of a wellbore extending into the Earth from surface and the pressure comprises a pressure P_0 at or near surface, and the method includes measuring the pressure P_0.

5. A method as claimed in claim 4, wherein the tubular comprises at least one tubular of a wellbore extending into the Earth from surface and the pressure is based on a pressure P_0 at or near surface, and an estimated density of the gas, and the method includes measuring the pressure P_0.

6. A method as claimed in any preceding claim, which further comprises defining a composition of the gas, wherein the step of using the acoustic velocity and the equation of state model to determine the temperature is performed based on the defined composition of the gas.

7. A method as claimed in any preceding claim, which further comprises determining various physical properties of the gas, such as density -based on the determined temperature combined with measured or know pressure and composition.

8. A method as claimed in any preceding claim, wherein the structure comprises inner and outer tubulars, e.g. casings, of a well, the inner tubular being arranged inside the outer tubular, and the containment region comprising an annulus between an inner tubular and the outer tubular.

9. A method as claimed in any preceding claim, wherein a plurality of intervals between reference points are defined, and the method includes:

determining acoustic velocities for the respective intervals based on the times of travel of the acoustic wave; and determining temperatures for the respective intervals using the acoustic velocities and the equation of state model.

10. A method as claimed in claim 9, which further comprises using the temperatures to obtain a profile of the temperature versus distance along the section of pipe.

11. A method of performing an inflow test in a well, using the temperature determined by performing the method according to any preceding claim to determine a rate of flow into the containment region of the structure.

12. A method of investigating and quantifying leakage rate of a fluid between a first pipe and a second pipe, wherein the first pipe is surrounded by at least a portion of the second pipe, where the pipes are arranged in a well in a ground, wherein the temperature of gas from an annulus surrounding a leakage site in the first pipe is determined by the method of any of claims 1 to 10.

13. Apparatus for performing the method as claimed in any preceding claim.

14. A computer program for computing the temperature from the obtained acoustic velocity in the method of any of claims 1 to 12.

15. A computer device comprising a processor which when executing the computer program of claim 14 is caused to determine the temperature from the obtained acoustic velocity.

16. A data carrier, data transmission medium, or data signal carrying any one or more of: the computer program of claim 14; the acoustic velocity data or travel time data obtained in performing the method of claims 1 to 12; and the determined temperature data obtained using the travel time data or the acoustic velocity data from performing the method of any of claims 1 to 12.

17. Apparatus for determining at least one temperature in fluid comprising gas in a containment region of a structure which comprises at least one tubular, the apparatus comprising:

at least one acoustic transmitter for producing an acoustic pulse to generate at least one acoustic wave to travel in the containment region between reference locations;

at least one sensor to detect the acoustic wave and determine the travel time of the acoustic wave between the reference locations; and

at least one determiner for determining the acoustic velocity from the travel time and using the acoustic velocity and an equation of state model to determine the temperature.

18. Apparatus as claimed in claim 17, wherein the sensor comprises a microphone.

19. Apparatus as claimed in claim 17 or 18, wherein the sensor is arranged to communicate data from the sensor to the determiner.

20. Apparatus as claimed in any of claims 17 to 19, further comprising at least one pressure sensor arranged for detecting the pressure in the containment region.

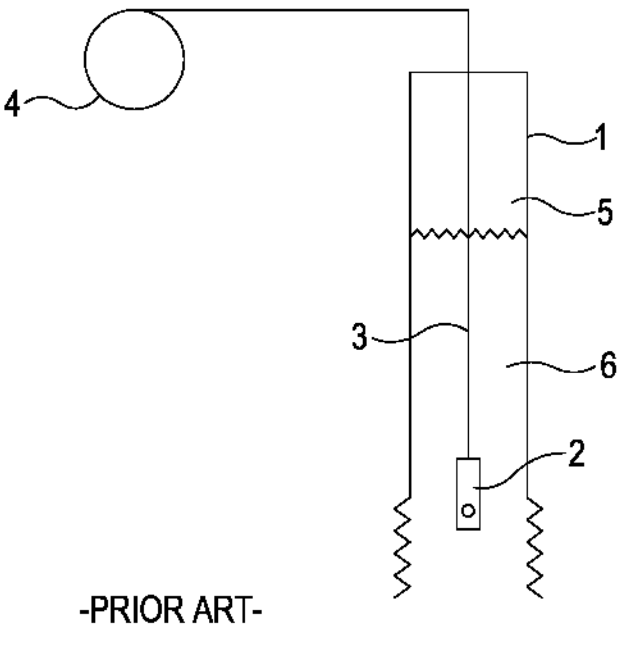

FIG. 1

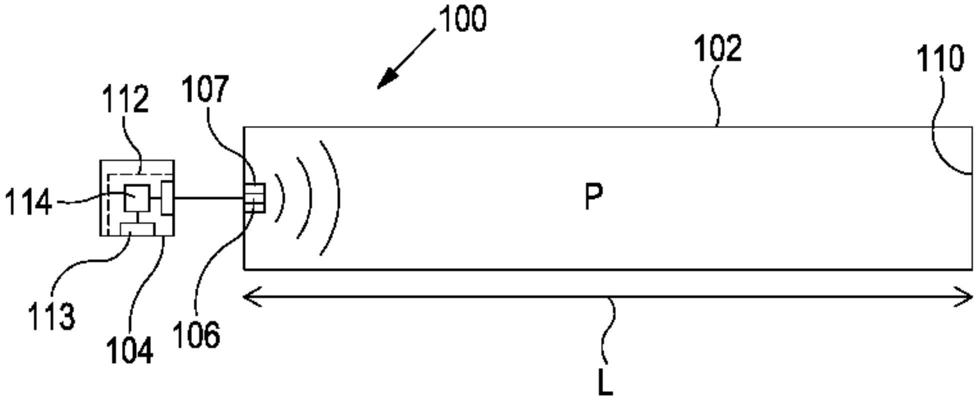

FIG. 2

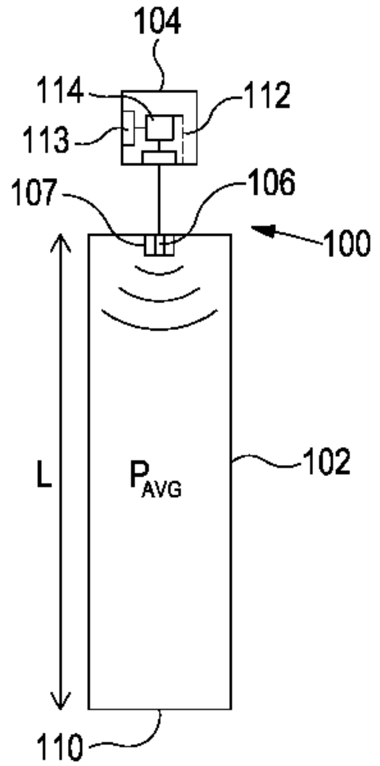
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FIG. 3

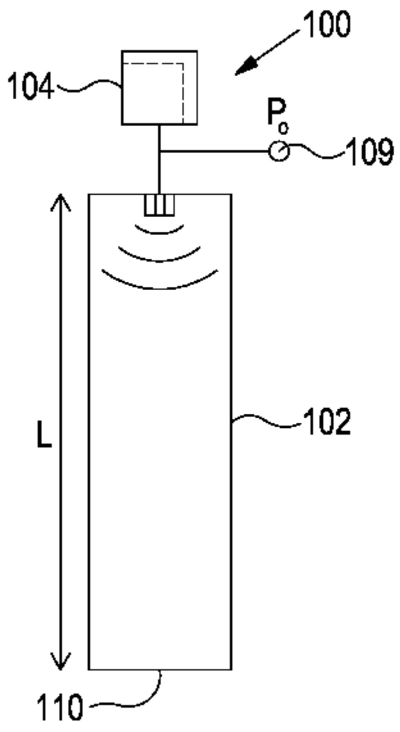
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FIG. 4

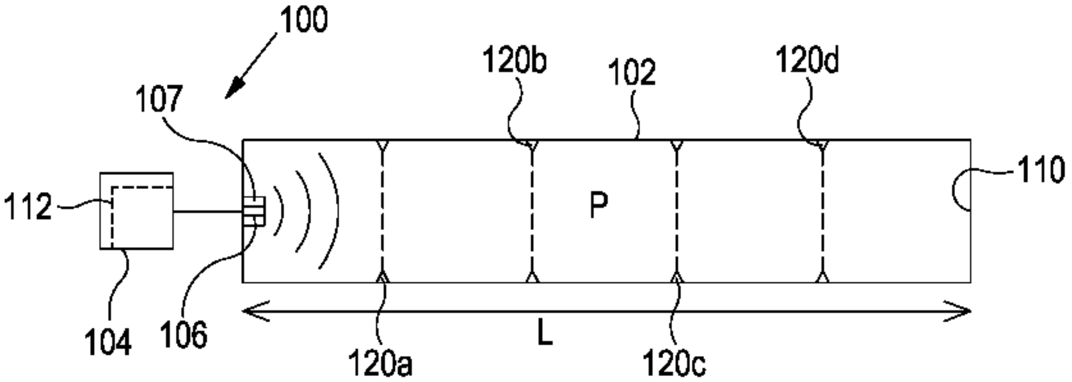
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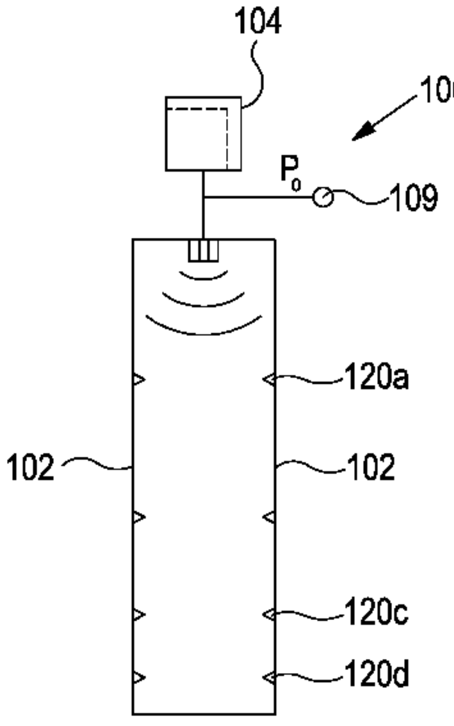
FIG. 5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120d

FIG. 6

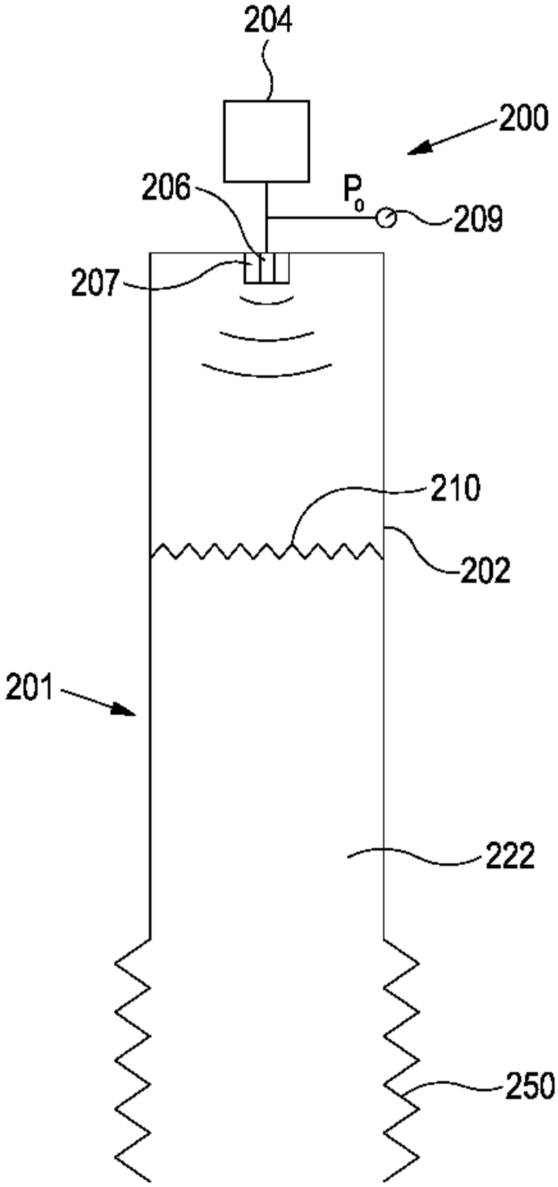
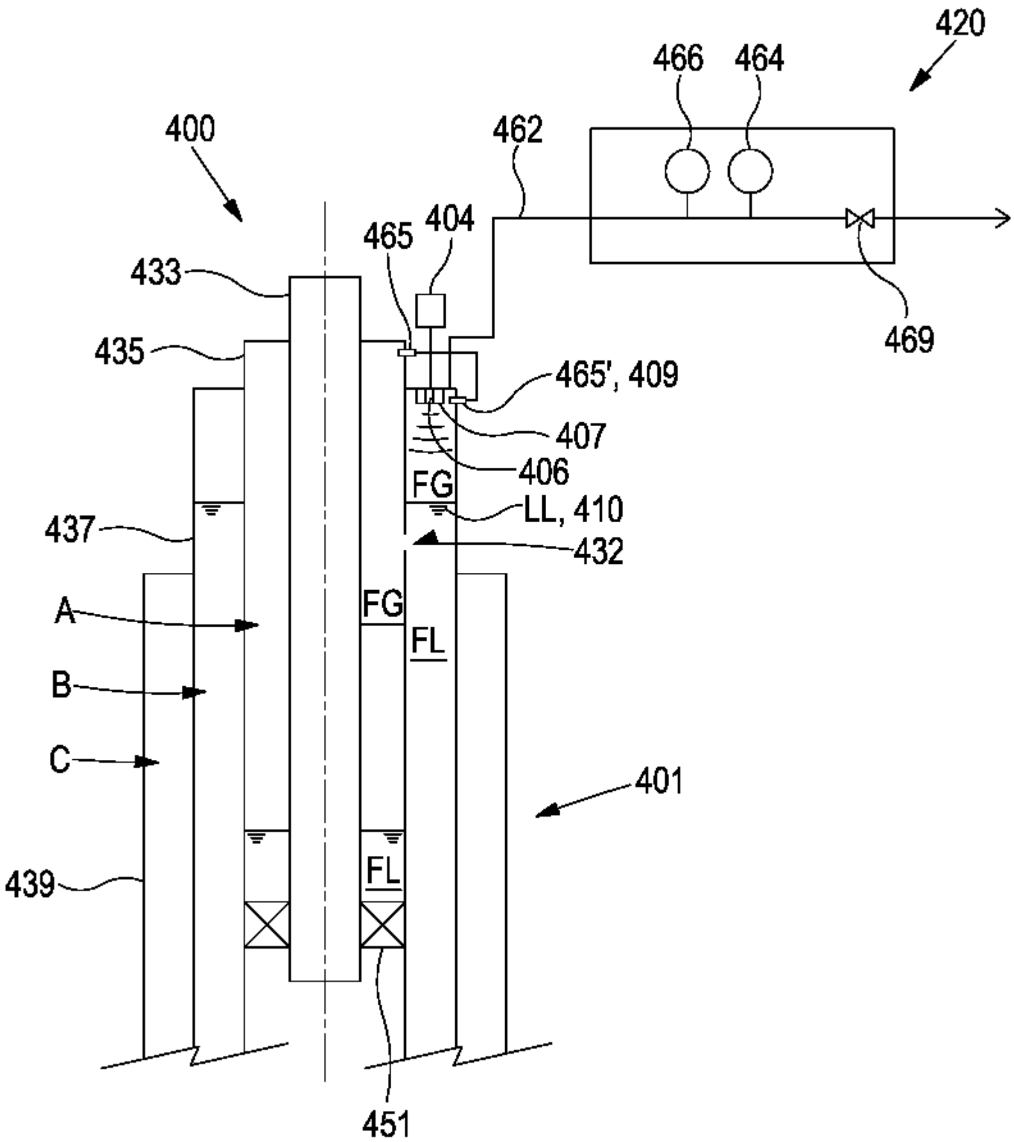


FIG. 7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FL
B
C
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439
FL
451

FIG. 8

INTERNATIONAL SEARCH REPORT

International application No
PCT/NO2020/050118

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B47/07 E21B47/14 G01K11/24
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B G01K

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

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

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	JP H11 14493 A (TOKYO GAS CO LTD) 22 January 1999 (1999-01-22) paragraph [0014] - paragraph [0027]; figures 1-3	1-20
X	US 2015/043612 A1 (WIEST ACHIM [DE] ET AL) 12 February 2015 (2015-02-12) paragraph [0017] - paragraph [0027]; figure 1	1-3,6,7, 13-17, 19,20
X	US 5 546 813 A (HASTINGS CALVIN R [US] ET AL) 20 August 1996 (1996-08-20) column 2, line 44 - column 9, line 25; figures 1, 5	1-3,6,7, 13-17, 19,20

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[X] Further documents are listed in the continuation of Box C.

[X] See patent family annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

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

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

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

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
21 August 2020	01/09/2020

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

1

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 5 624 188 A (WEST DAVID A [US]) 29 April 1997 (1997-04-29) the whole document -----	1-20
T	Jerry Paul Smith ET AL: "UNDERSTANDING AGA REPORT NO. 10, SPEED OF SOUND IN NATURAL GAS AND OTHER RELATED HYDROCARBON GASES", , 12 January 2011 (2011-01-12), XP055724336, Retrieved from the Internet: URL:https://asgmt.com/wp-content/uploads/pdf-docs/2011/1/Q10.pdf [retrieved on 2020-08-21] the whole document -----	

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/NO2020/050118

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