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(54) **IMPROVED ACCURACY OF MEASUREMENTS OF FLOW RATE AND LEAKAGE DETECTION OF SINGLE OR MULTIPHASE PRODUCED FLUID IN A WELL**

(57) The present invention related to an apparatus for producing fluid from a well using gas lift technique and a method for determining flow characteristics of produced fluid in a well during production operations

using. The present invention also describes an apparatus and method to identify, quantify and characterise leakage in a well.

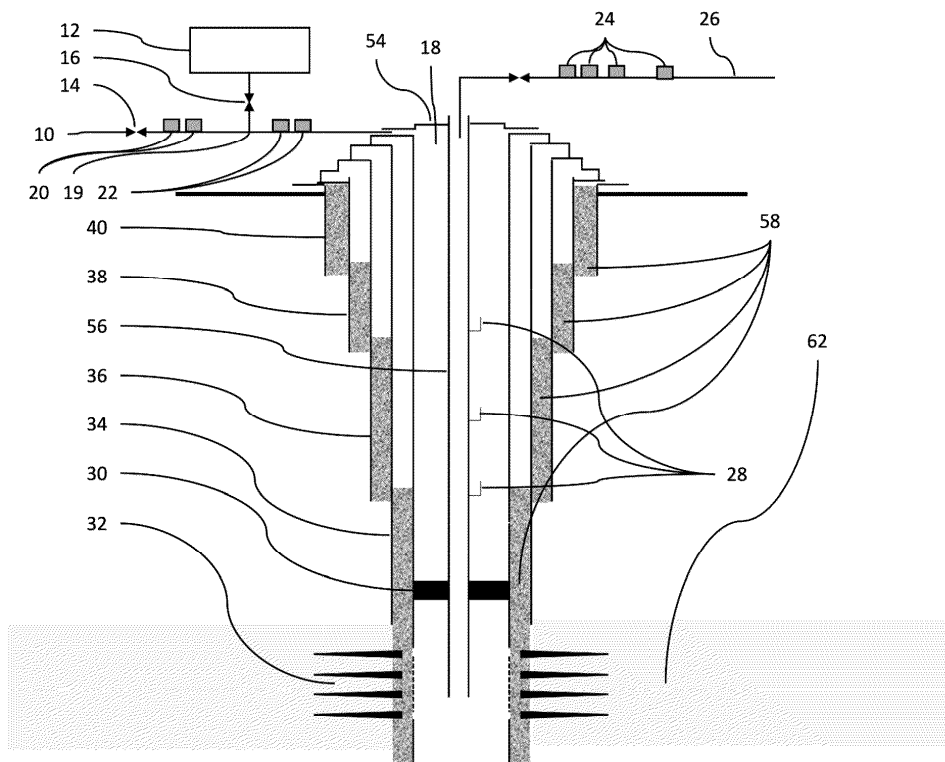


Fig. 1

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Description

[0001] The present invention relates to an apparatus for measuring parameters of a petroleum well and a method for determining flow characteristics of fluid in a well during production, injection or testing operations using the apparatus. The present invention also describes an apparatus and method to identify, quantify and characterise leakage in a well. More particularly and preferably it concerns a method and apparatus to investigate leakage between the multiple concentric pipes (e.g. annuli) found in a completed well and includes leakage between the outermost pipe and the subsurface formations. Leakage is defined as any unexpected flow between pipes in either direction, including to or from the subsurface material such as rocks.

[0002] Accurate measurements of flow parameters of produced fluids from a well are necessary to optimise petroleum field management in situations where any artificial lift such as submersible pumps or gas lift are employed. In the absence of dependable flow information, the control parameters for any artificial lift system are likely to be sub-optimal and energy will be wasted, either as excess injected gas, or excess electricity to the pump.

[0003] Flow meters are available to measure average flow velocities, with mass and volume rates calculated from this, however, industry experience is that flow meter accuracy is poor, particularly for measuring velocities of multiphase fluids, and they are expensive to install. Clamp-on meters are simpler, and cheaper, but these often perform poorly for gas flows. As a result, many wells do not have accurate methods to determine flow rates.

[0004] If accurate measurements of flow rates in multiphase settings is required, the present standard industry solution is to install a separator in the production line and measure the mass or volume of each phase over an extended time. The use of a separator will give a more accurate average result, but there is considerable delay in getting these values and the equipment itself is large and expensive.

[0005] Velocities of flowing fluids have been measured for many centuries by observing the motion of an introduced object into the flow. Chip logs and Pooh sticks are examples for measuring velocities in open channels. In closed ducts, it is more common to introduce another fluid with similar fluid dynamic properties that may easily be distinguished from the main flow, such as coloured dyes or gases. If the flow is visible, these tracers allow the observer to evaluate, either qualitatively or quantitatively, a range of flow parameters. In the case of the opaque steel pipes used in production wells and throughout the petroleum industry, direct visual observation of the tracer has not been considered.

[0006] A recent review of tracer surveys with the aim of product and service improvement identified a significant operational risk associated with reliance on single measurement devices such as sensors. Whilst there are analytical ways to correct for measurement errors, it is not always obvious whether there is a problem with the data supplied by the client, an anomaly in the well that needs correcting, or an issue with one of the measurement devices. These issues can sometimes just be positioning or installation errors, so if the measurement devices were tested, they would be found to be within specification.

[0007] The gas lift technique is described in detail in books (Standard Handbook of Petroleum and Natural Gas Engineering / [edited by] William C. Lyons, Ph.D., P.E., Gary J. Plisga, B.S., Michael D. Lorenz, B.S. Third edition, Amsterdam, Boston: Elsevier: GPP; Mitra "Principles of Artificial Lift" First edition, Allied Publishers Pvt., Limited, 21. March 2016; Hernandez, "Fundamentals of Gas Lift Engineering", first edition, Elsevier, 2016; Zemel "Tracers in the Oil Field", First edition, Elsevier, 1995).

[0008] EP 3 803 047 B1 discloses a method for determining a parameter of a flow of a produced fluid in a well. In this method, a tracer can be measured after injection into an injection line before entering the production fluid and then after the produced multiphase fluid is retrieved from the well. However, it is unclear, how the flow of the fluid is calculated or determined.

[0009] WO2017065863A1 discloses a method for monitoring gas lift wells using minimal concentration tracer materials. A tracer material is injected into the annulus between the production line and the casing. The patent application discusses diffusion of the tracer after injection into the injection gas. However, this diffusion is only estimated based on peak broadening when measuring tracer concentration from the produced multi-phase fluid from the well.

[0010] WO2015191026A1 discloses gas lift analysis and troubleshooting.

[0011] US 2007/0051511A1 describes a system and method for breach detection in petroleum wells.

[0012] American Petroleum Institute (API) published simplified diagnostic criteria for Bleed-Down/Bleed-Up (B/B) test analysis published in API Recommended Practice (RP) 90-1, Annular Casing Pressure Management for Offshore Wells 2nd ed August 2021, API Recommended Practice (RP) 90-2, Annular Casing Pressure Management for Onshore Wells 1st ed April 2016; National Archives and Records Administration: College Park, MD, USA) and 10 CFR 250 Subpart E. The criteria only consider if the pressure would Bleed-Down to zero and rebuild to its initial value within 24 hours.

[0013] EP 2 446 116 B1 describes an apparatus and method for detecting and quantifying leakage in a pipe and specifically relates this method and apparatus to flow between annulus A and B in a petroleum well. Their claim describes a direct method of quantifying the leak rate without the Bleed-Up phase of the API standard which claims to

save time.

[0014] Kazemi and Wojtanowicz Kazemi (M., & Wojtanowicz, A. K. (2022). Improved method for testing integrity loss of wells with sustained casing pressure. *Energies*, 15(10), 3632.) describe mathematical models for the bleed-down, constant, and bleed-up phases of the API test and highlight the sensitivity of test results to the selection of test parameters by the operator. This suggests that the method and apparatus of EP 2 446 116 B1 is an oversimplification of the complexities of fluid leakage through porous media such as cements, Newtonian fluids like water, and non-Newtonian fluids such as drilling muds.

[0015] The problem according to the present invention is the provision of a technology to improve the ability to determine the flow of the production fluid in a petroleum well and to improve the accuracy of measured leak rates between annuli and to understand the relationship between multiple variable leak rates across annuli in response to pressure variations.

[0016] In a first embodiment, the problem according to the invention is solved by an apparatus for measuring parameters of a petroleum well, comprising:

a. a production line, transporting production fluid out of the well,

b. at least one annulus around the production line,

c. at least one upstream measurement device configured to determine at least one parameter of the fluid in the at least one annulus, and

d. at least one downstream measurement device configured to determine at least one parameter of the produced fluid.

[0017] An upstream measurement device according to the present invention is a measurement device measuring a parameter of fluid in the at least one annulus (or annuli if there are more annuli).

[0018] A downstream measurement device according to the present invention is a measurement device measuring a parameter of fluid in the production line.

[0019] This invention also overcomes the limitations of prior art by preferably making continuous measurements of temperature, density, liquid levels, flow rate and pressure across all annuli. Accurate continuous measurement of the flow rate and data from a plurality of measurement devices such as sensors of various types across the entire test process provides a richer dataset for analysis and characterisation of the leak or leaks and allows the 24-hour constant pressure period to be shortened thus achieving the time-saving gains claimed in EP 2 446 116 B1 without loss of accuracy.

[0020] The invention further simplifies and improves on the method and apparatus specified in EP 2 446 116 B1 by removing the need for a pressure regulating valve downstream of the measuring arrangement since preferably a constant pressure difference between the annuli is not needed in this invention.

[0021] Understanding the nature of the flow in the injection line at the point, where the tracer is injected is important in any consideration of the mixing of the tracer material and the injection gas. No prior art appears to have any measurement devices such as sensors on the injection line to determine the flow rate at the point the tracer is injected. Some prior art has a mass flowmeter on the tracer line to measure the rate of tracer inflow, but that does not provide any information on the behaviour or flow regime of the gas the tracer material is injected into.

[0022] The produced fluid may comprise gas components, liquid components and solid components. The gas components may comprise naturally occurring gases in a subsurface fluid reservoir, injection gas and/or tracer material. The liquid components may comprise liquids from a subsurface fluid reservoir, tracer materials and/or water. The solid components may comprise solid particles such as pieces of rock formation from a subsurface reservoir and/or tracer material.

[0023] The well may be an offshore or onshore well.

[0024] Preferably, there are communication points between the production line and the at least one annulus.

[0025] Preferably, the apparatus does not comprise a pressure regulating valve except for a mandatory high-pressure regulating valve for safety.

[0026] Preferably, the apparatus also comprises one or more of: an injection gas source, a tracer source, an injection gas control valve, a tracer inflow control valve, a fluid analyser (such as a Raman spectrometer), an injection line, a tracer inlet, a production line output, communication points (such as gas lift valves), a packer, perforation, a production casing, an intermediate casing, surface casing, conductor casing, an A-annulus, a B-annulus, a C-annulus, a D-annulus, a pressure sensor, a flow meter, a wellhead, cement, a hanger, an array of measurement devices, flow valves, a control unit and/or wireless gas cards.

Gas Lift Operations

- [0027] The apparatus according to the present invention can preferably used in gas lift operations.
- [0028] Preferably, at least one annulus is an injection line, transporting injection gas into the well.
- 5 [0029] The production line may be a typical production line for gas lift operations.
- [0030] The injection line may be an annulus between a well casing and the production line.
- [0031] The communication points may be e.g. gas lift valves or leaks in the production line.
- [0032] Preferably, the apparatus also comprises an injection gas control valve. This valve can adjust the rate of injection of an injection gas to one or a plurality of wells.

Using a Tracer

[0033] Preferably, the apparatus also comprises a tracer-injection location upstream from the communication points (preferably in the injection line or an annulus), where a tracer substance can be injected into the injection line or an annulus.

[0034] Preferably, at the tracer-injection location upstream from the communication points there may be a valve located between a source of tracer material and the injection line. The valve may preferably be an electronically actuated valve. This would have the advantage that the amount of tracer material can automatically be adjusted to optimize the evaluation of the flow characteristics of the produced fluid. Preferably, the position of the valve is determined taking into account the flow characteristics that are determined in the method according to the present invention. The tracer material may be selected from the group gases, liquids, dyes, particles, RFID chips, radioactive nuclides, fluorescent materials, solid objects and/or mixtures thereof. The tracer material preferably is selected from the group of carbon dioxide, nitrogen, helium, argon, xenon, sulphur hexafluoride, a radioactive material, and/or mixtures thereof. The source of the tracer material may be a bottle or a pipeline. Preferably, the tracer-injection location is located above the surface (e.g. of the land or the sea or water) for better maintenance.

[0035] Preferably, the at least one upstream measurement device is located upstream of the tracer-injection location (preferably in the injection line or an annulus). It can be configured to measure a parameter of fluid before a tracer substance is injected.

[0036] The advantage of this invention is to be able to determine an optimal set of control parameters to deliver a given production flow rate based on a more complete picture of the tracer behaviour and, by extension, the behaviour of the injection and production fluids under investigation, using a plurality of measurements both upstream and downstream of the tracer-injection location. Locating measurement devices such as sensors upstream of the injection point allows determination of the flow velocity at the injection point which affects the way that the tracer is mixed with the injection gas. The prior art ignores this aspect.

[0037] Preferably, where a tracer injection communication point is located along the at least one annulus, so that a tracer substance can be introduced into the annulus, at least three upstream measurement devices are located within at most 5 m of the tracer injection communication point, where at least one of these upstream measurement devices is a flow meter and at least two of these upstream measurement devices are sonic sensors.

Measurement Devices

[0038] Preferably, a multitude of measurement devices is employed in this present invention. These can even be employed in the form of arrays of measurement devices.

[0039] It is apparent that sensitivities of all measurement devices such as sensors are variable and change during the operational life of the measurement device. Moreover, measurement devices such as sensors measuring different phenomena, using different techniques, have different sensitivities. Gas sensors generally have different sensitivities to different gases, even gas chromatographs and spectrometers. The method according to the present invention preferably uses frequentist statistics to combined measurements with different sensitivities, Bayesian statistics to continually assess and update the accuracy of each sensor in the array in the presence of drift and degradation.

[0040] The measurement devices can preferably be flow meters, sonic sensors, pressure gauges, density sensors, temperature sensors, spectrometers or combinations thereof (e.g. when using a plurality of measurement devices).

[0041] The apparatus preferably does not rely on the annulus functioning as a separation chamber for gas and liquid; instead, preferably it measures fluid flow directly without requiring gas-liquid separation in the annulus. This is a clear advantage of the present apparatus.

[0042] In this invention, preferably measurement devices such as sensors are located upstream of the tracer-injection location to determine the flow rate in the gas injection line or in an annulus immediately before the tracer is injected. Therefore, at least one upstream measurement device (preferably at least 3 upstream measurement devices) are located upstream of the tracer-injection location.

[0043] The use of at least one upstream measurement device for determining at least one parameter of the injection gas that is located upstream of the tracer-injection location has not been known in the prior art. So far, the tracer concentration and diffusion characteristics have been estimated just by knowing the amount of tracer injected into the injection line and measuring e.g. the broadening of the tracer concentration signal in the produced fluid. The upstream measurement device has the clear advantage of now being able to get a much more accurate understanding of the flow characteristics of the injection gas before the tracer material is injected (such as the gas injection rate of the injection gas). The upstream measurement devices can preferably be a flow meter, sonic sensor, a pressure gauge, density sensor, temperature sensor, a spectrometer or combinations thereof (e.g. when using a plurality of measurement devices). Preferably, the at least one upstream measurement device is in communication with an annulus. This annulus could be suspected leakage site. It can be useful in the present invention to have at least two upstream measurement devices, where at least one of the upstream measurement devices is a spectrometer and at least one upstream measurement device is a sonic sensor. The spectrometer can be an infrared spectrometer, an UV/VIS spectrometer, a Raman or a mass spectrometer. Especially preferred is a Raman spectrometer. The at least one measurement device is preferably configured to directly measure the fluid in the injection line. In the prior art, often there is the need for a separator, which may make things more complicated and expensive. In the prior art, often a gas chromatograph is employed, which takes at least several minutes for each measurement and also needs a separator, to separate the gas from the liquid from the injection line. With the at least one upstream measurement device, it is now possible to perform real-time measurements e.g. on the flow characteristics of the injection gas. So far, there was prejudice against the need for such upstream measurement device, since it was thought that the flow characteristics of the injection gas were ideal and the diffusion of the tracer injected into the injection gas was also ideal with immediate diffusion of the tracer in the injection gas. However, the inventor found that this is not the case. Using Raman technology as a preferred embodiment, this invention allows analysis of gas, liquid and solid. This is a big advantage of using Raman technology over solutions presented in the prior art.

[0044] The prior art so far does not use CO₂ sensors with a near real-time response. For nitrogen tracers, using gas chromatography each sample takes about five minutes to process since the measurement technique uses gas chromatography. Samples can be taken at a higher rate, but the results will back up and no real-time analysis is available.

[0045] This invention preferably uses Raman spectroscopy; e.g. for measuring the tracer with a sample interval of e.g. 7 seconds. The software algorithm the inventor has created to process and present each sample runs in less than three seconds giving the new invention the capability to provide analysis and present results that are updated in near-real-time e.g. every 10 seconds.

[0046] Preferably, at least one of the upstream or downstream measurement devices (most preferably the mentioned Raman spectrometer) is configured to have a sample interval in a range from 0.1 to 10 seconds.

[0047] The at least one downstream measurement device located downstream of the communication points for determining at least one parameter of the produced fluid may be located above the surface. This at least one downstream measurement device located downstream of the communication points may also be located subsurface or downhole. The at least one downstream measurement device located downstream of the communication points may be a sonic sensor (e.g. a microphone, but not necessarily in the audio frequency range), a spectrometer or a flow meter or combinations thereof (e.g. when there are several measurement devices). The spectrometer may be in any part of the electromagnetic spectrum, including infrared, it may be a Raman spectrometer, or it could be a mass spectrometer. However, preferably, the spectrometer is a Raman spectrometer.

[0048] Preferably, there are at least two downstream measurement devices located downstream of the communication points. So far, there was mostly only one gas chromatograph or infrared spectrometer in this location. Preferably, the at least two downstream measurement devices are different from each other. The at least two downstream measurement devices can be selected to be different and from the group of infrared spectrometer, gas chromatograph, UV/VIS spectrometer, mass spectrometer, Raman spectrometer, sonic sensor (e.g. microphone) and/or flow meter.

[0049] The prior art uses gas detectors for CO₂ or gas chromatography for nitrogen. Gas chromatography needs a separator and, in prior art embodiments, cannot handle the liquid phase. The use of gas chromatography in prior art for the determination of a nitrogen tracer is problematic due to the use of nitrogen as the carrier gas in the gas chromatograph, this means that the concentration of nitrogen is not directly measured but somehow inferred from concentrations of measured components.

[0050] Preferably, in this invention a number of different measurement devices to measure the gas in the production line are employed. A preferable measurement device (e.g. for determination of total gas composition) is a Raman spectrometer, since all components in a natural gas mixture, including nitrogen, have readily detectable vibrational peaks in their Raman response. This can be any one or more of the above-mentioned measurement devices (e.g. upstream or downstream measurement devices). A Raman spectrometer responds to Raman scattering, which is the scattering of photons from molecular bonds with different scattering modes. This technique does not require separation of gas and liquid phases with a separator. The presence of liquid hydrocarbons in the production line can cause

fluorescence but techniques exist to correct for the known fluorescent frequency spectrum of hydrocarbons. Preferably, the at least one upstream measurement device located upstream of the tracer-injection location is a Raman spectrometer. Preferably, the at least one downstream measurement device located between the tracer-injection location and the communication points is a Raman spectrometer. Preferably, the at least one downstream measurement device located downstream of the communication points is a Raman spectrometer.

[0051] Preferably, the apparatus comprises at least one downstream measurement device located between the tracer-injection location and the communication points. This has the advantage of being able to get a much better understanding of the diffusion characteristics of the tracer material in the injection gas. So far, it was basically assumed that the tracer material is immediately diffused in a homogenous fashion. The inventor found out that this is not the case. Especially, in combination with the measurement(s) of the at least one upstream measurement device, the diffusion of the tracer material can be understood much better. If, for example, it is possible to determine the gas injection rate of the injection gas with the measurement(s) of the at least one upstream measurement device, then determining e.g. the concentration of the tracer material in the injection gas using the at least one downstream measurement device located between the tracer-injection location and the communication points, the diffusion characteristics of the tracer material inside the injection gas can be determined much more accurately as compared to using simply the injected amount of tracer material and the tracer concentration in the produced fluid. So, the combination of the at least one downstream measurement device located between the tracer-injection location and the communication points and the at least one upstream measurement device for determining at least one parameter of the injection gas that is located upstream of the tracer-injection location has a clear advantage over the prior art. The at least one downstream measurement device located between the tracer-injection location and the communication points may be a sonic sensor (e.g. a microphone), a spectrometer or a flow meter or combinations thereof (e.g. when there are several measurement devices). The spectrometer may be an infrared, UV/VIS, Raman or mass spectrometer. However, preferably, the spectrometer is a Raman spectrometer. The downstream measurement device located between the tracer-injection location and the communication points can preferably be a spectrometer e.g. to measure the concentration of tracer material in the injection gas.

[0052] Preferably, there is a plurality of the mentioned upstream and downstream measurement devices, more preferably the apparatus comprises 4 to 500, even more preferably 10 to 500, most preferably 30 to 500, upstream and downstream measurement devices. This was thought to not be achievable and necessary so far in this technical field. This invention preferably deploys a number of lower-cost sensors in addition to the existing sensor configurations to provide supplementary information which improves the accuracy and reproducibility of measurements. Preferably, the field engineer is presented with a more complete picture of flow in the gas injection line and the produced fluids line. This invention preferably also uses different sensor types to overcome the limitations of using a single type. For example: ultrasonic flow rates sensors are accurate but can be inaccurate for gas flow in thin high-pressure pipes. The use of a multiple sonic sensors at different frequencies in different locations can overcome these limitations.

[0053] Preferably, the sonic sensors are acoustic sensors or ultrasonic sensors.

[0054] Preferably, 10 to 99% of the upstream and downstream measurement devices are sonic sensors. Preferably, 10 to 100% of the sonic sensors are ultrasonic sensors. Preferably, 10 to 100% of the upstream and downstream measurement devices (especially the sonic sensors) are configured to transmit data via Bluetooth® or other wireless transmission protocols. Preferably, 10 to 100% of the upstream and downstream measurement devices (especially the sonic sensors) are battery operated. Preferably, the sonic sensors are configured to transmit data via wireless transmission protocols (such as Bluetooth® or other wireless transmission protocols) and/or to be battery operated. Preferably, the sonic sensors are distributed along the stream starting from the location of the injection gas control valve to the production line output such that not more than 30% of the acoustic sensors are located in any of 10% of the distance between the location of the injection gas control valve and the production line output. Preferably, at least two sonic sensors are configured to record sonic data at frequencies that differ by at least 10%. This way there preferably is an additional mode of measurement for flow velocity in all sections traversed by the tracer. The sonic sensors may preferably be linked using a wireless transmission protocol (e.g. Bluetooth® Low Energy) mesh, which allows a large number of sensors to be connected wirelessly.

[0055] Preferably, the apparatus according to the present invention also comprises at least one device for emitting sonic waves. More preferably, the apparatus according to the present invention comprises at least two devices for emitting sonic waves. Preferably, these at least two devices for emitting sonic waves emit ultrasonic waves at different frequencies. Preferably, at least one of these devices for emitting sonic waves is configured to emit ultrasonic waves. Employing devices for emitting sonic waves has the advantage to overcome the limitations of energy attenuation. Preferably, the devices for emitting sonic waves are transducers (e.g. ultrasonic transducers). The prior art does not consider the impact of sub-optimal placement of ultrasonic transducers. This way, the present invention allows to advise on transducer placement using multiple channels and for auto-correction for liquid separation.

[0056] Preferably the above-mentioned flow parameter of the injection gas is the injection rate of the injection gas.

[0057] At least some of the mentioned measurement devices may comprise containers to collect samples for later

analysis.

[0058] Some of the above-mentioned measurement devices may be positioned arbitrarily both upstream and downstream of the tracer injection location. In some cases, the exact location of measurement devices may not be critical. The apparatus has the capability to determine the location of measurement devices using a cylindrical triangulation algorithm. For some measurement configurations more optimal locations may be identified. Examples of more-optimal locations could include but is not limited to, avoidance of physical obstructions, orthogonal measurement locations for the determination of vector fields, shaded locations, avoidance of corrosion on pipelines.

[0059] Preferably, there is at least one heterogeneous array of measurement devices on the production line.

[0060] Preferably, there is at least one heterogeneous array of measurement devices on any annulus or injection line.

[0061] Preferably, there is at least one heterogeneous array of measurement devices in pressure communication with any annulus, any combination of annuli, or all annuli.

[0062] Heterogeneous in the sense of the present invention preferably means that the measurement devices in one array are not all of the same type.

[0063] Array in the sense of the present invention preferably means that the measurement devices of the array are located in proximity to each other, more preferably each measurement device of a particular array has a smaller distance to all other measurement devices of the same array compared to any measurement device of another array.

[0064] Preferably, the upstream and downstream measurement devices include at least 2 sonic sensors and at least one pressure sensor.

[0065] Preferably, the apparatus comprises 4 to 100 upstream and downstream measurement devices.

[0066] Preferably, the apparatus comprises at least 5 upstream measurement devices and/or at least 5 downstream measurement devices.

[0067] Preferably, at least one measurement device can also be a gas card. A gas card is used to measure the gas concentration (e.g. CO₂) from a fluid sample. The gas card can be a wireless gas card. Preferably, at least four measurement devices are wireless gas cards.

Annuli

[0068] The apparatus according to the invention comprises at least one, and preferably at least two, annuli. Preferably, the apparatus comprises a plurality of measurement devices (preferably as defined above). Preferably, at least one measurement device per annulus is in communication with the respective annulus. Preferably, measurement devices are in communication with at least two annuli, more preferably with all annuli. Preferably, the apparatus is configured to monitor and/or measure properties of fluids across all annuli concurrently and/or continuously. Preferably, the apparatus is configured to (continuously) measure pressure differentials, mass flow rates, temperatures, densities and/or liquid levels across all annuli concurrently and/or continuously. This helps to detect and quantify leakage. This has the advantage that no extended test at zero or near zero differential pressure between adjacent annuli is required. The flow at zero pressure may be determined by analysis of the relationship between continuously measured pressure differential and continuously measured mass flow.

[0069] Preferably, the apparatus is configured to dynamically adjust the flow measurement by selectively closing flow paths with larger range flow meters as flow rates decrease, allowing accurate measurement through flow meters with higher sensitivity.

[0070] In the construction of oil and gas wells, multiple concentric casings and tubing strings are installed within the wellbore to ensure structural integrity and zonal isolation. This arrangement creates a series of annular spaces, known as annuli, between the different layers of casing and tubing. These annuli are critical for monitoring well integrity and detecting any leakage that may occur between the casings. The annuli are typically designated from the innermost to the outermost spaces using letters such as A, B, C, and D.

[0071] Preferably, the apparatus according to the present invention comprises a production casing. Preferably, the apparatus according to the present invention comprises an A-annulus. The A-annulus, or production annulus, typically is the annular space between the production line / production tubing and the production casing. The inner wall of this annulus is formed by the production tubing / production line, which is the innermost conduit through which hydrocarbons are transported from the reservoir to the surface. The outer wall is formed by the production casing, which provides structural support and isolates the wellbore from surrounding geological formations at production depths. The A-annulus preferably allows for pressure monitoring and preferably serves as a conduit for various interventions, such as chemical injections or gas lift operations. Preferably, monitoring this annulus helps detect leaks in the production tubing or casing. Preferably, the A-annulus is the injection line. Preferably, the A-annulus comprises at least one pressure sensor and/or at least one flow meter.

[0072] Preferably, the apparatus according to the present invention comprises an intermediate casing. Preferably, the apparatus according to the present invention comprises a B-annulus. The B-annulus, or intermediate annulus, lies

between the production casing and the intermediate casing. The inner wall is the production casing, and the outer wall is the intermediate casing, which adds another layer of protection and isolates deeper formations. Monitoring the B-annulus is preferable in this invention for detecting leaks from the production casing. It provides an additional barrier for well control and helps prevent fluid migration between different geological zones. Preferably, the B-annulus comprises at least one pressure sensor and/or at least one flow meter.

[0073] Preferably, the apparatus according to the present invention comprises a surface casing. Preferably, the apparatus according to the present invention comprises a C-annulus. The C-annulus is the space between the intermediate casing and the surface casing. The inner wall is the intermediate casing, and the outer wall is the surface casing, which is cemented from the surface to a certain depth to protect shallow freshwater zones and provide initial structural integrity. Preferably, monitoring the C-annulus helps detect any leaks in the intermediate casing and ensures the integrity of the well at shallower depths. Preferably, the C-annulus comprises at least one pressure sensor and/or at least one flow meter.

[0074] Preferably, the apparatus according to the present invention comprises a conductor casing. Preferably, the apparatus according to the present invention comprises a D-annulus. The D-annulus, or outermost annulus, preferably exists between the surface casing and the conductor casing or directly against the formation if no conductor casing is present. The inner wall is the surface casing, and the outer wall is either the conductor casing or the surrounding geological formation. The D-annulus is preferable for environmental protection. Preferably, monitoring this annulus ensures that the outermost barriers of the well are intact, preventing any potential leaks into the surrounding environment. Preferably, the D-annulus comprises at least one pressure sensor and/or at least one flow meter.

[0075] The present invention enhances well integrity monitoring by preferably deploying a (comprehensive) array of sensors within each annulus (A, B, C, D). This approach allows for concurrent monitoring and detection of leaks across all annuli, providing a detailed understanding of the well's condition. Sensor deployment preferably includes pressure sensors installed within each annulus to detect pressure variations that may indicate fluid migration or casing leaks, temperature sensors to monitor temperature changes associated with fluid movement, density sensors to measure the density of fluids in the annuli and help identify gas ingress or loss of well fluids, and/or flow meters equipped with different ranges and sensitivities to measure the flow rates of fluids entering or exiting an annulus. High-frequency pressure transient sensors can preferably detect rapid pressure fluctuations characteristic of sudden leak events, and devices for modulated pressure waves utilize modulated pressure waves to provide continuous, real-time detection of liquid levels within each annulus.

[0076] Preferably, measurement devices (such as flow meters, pressure gauges, density and temperature sensors) are positioned in each annulus. Preferably, each of these measurement devices is in communication with an annulus surrounding a suspected leakage site.

[0077] By installing measurement devices such as (pressure) sensors in each annulus, the apparatus offers a holistic view of the well's integrity, enabling the detection of leaks at any casing level. Preferably, at least one pressure sensor is installed in each (aforementioned) annulus of the apparatus. This way, e.g. the pressure differential can be recorded between the annuli. The high sensitivity and continuous monitoring capabilities allow for the early identification of leaks, preventing minor issues from escalating into major failures. Preferably, data analysis algorithms process the sensor data to accurately characterize the location, size, and nature of any detected leaks. Preferably, automation of data collection and analysis minimizes the reliance on manual interventions, reducing the potential for human error. The ability to detect and quantify leaks without extended testing periods or the need for constant pressure differentials improves overall operational efficiency.

[0078] The physical walls that form the boundaries of the annuli in the well are preferably utilized in the invention to house and support the sensor arrays. Preferably, these walls are the casings - e.g. steel pipes of varying diameters and specifications, cemented into place to provide structural support and zonal isolation-and the production tubing, the inner conduit through which production fluids flow to the surface. Each annulus is thus encapsulated by an inner wall (the outer surface of the inner casing or tubing) and an outer wall (the inner surface of the outer casing). This configuration allows the sensors to be strategically placed for optimal monitoring of the annular spaces.

[0079] In the A-annulus, measurement devices such as sensors are preferably positioned between the production tubing and production casing to monitor the immediate production environment. In the B-annulus, measurement devices such as sensors are preferably positioned between the production casing and intermediate casing to detect leaks from the production casing into deeper formations. In the C-annulus, measurement devices such as sensors are preferably located between the intermediate casing and surface casing to monitor the integrity of the intermediate casing. In the D-annulus, measurement devices such as sensors are preferably deployed between the surface casing and conductor casing or formation to ensure environmental protection by monitoring the outermost barriers.

[0080] By leveraging the annular spaces formed between the concentric casings and tubing strings, the invention provides a robust system for detecting and quantifying leaks within a well. The comprehensive measurement device deployment across all annuli enables continuous, real-time monitoring of critical parameters, significantly enhancing well integrity management. This approach not only allows for early leak detection but also provides detailed leak

characterization, facilitating prompt and effective remedial actions to maintain safe and efficient well operations. Understanding and utilizing the physical structure of the well's annuli, the invention significantly improves the ability to monitor and maintain well integrity, ensuring the safety of operations and the protection of the environment.

[0081] Preferably, at least one measurement device per annulus (such as a pressure sensor and/or a flow meter) is in communication with at least two annuli, more preferably with each annulus. Preferably, the pressure sensors are configured to measure the pressure in each annulus, and the flow meters record flow from or to each annulus. Preferably, at least two flow meters have a different measurement range and/or a different resolution. The range of flow can vary a lot. Having meters that are accurate in different ranges is an advantage. A big flow meter can measure big flows accurately, but small flows are below the resolution. Small flow meters are accurate for low flow rates, but large flow rates are off the scale. Preferably, the pressure sensors are high-frequency pressure transient sensors. Preferably, at least one pressure sensor and/or flow meter per annulus is in communication with the respective annulus.

[0082] Preferably at least two mass flow meters with different ranges and/or sensitivities are located in at least two annuli, more preferably in all annuli. This improves measurement of flow at low pressure differentials.

[0083] Preferably, at least one valve is located downstream of a pressure sensor or pressure sensors. This way, a variable and quantifiable pressure differential between any of the annuli surrounding locations of possible leakage can be provided. Preferably, the valve is connecting the annulus, where the pressure sensor (or pressure sensors) is measuring the pressure, with a neighbouring annulus or the production line.

[0084] Preferably, control valves are located in each annulus, so that all neighbouring annuli are connected with control valves. These control valves can be adjusted to provide variable pressure differences between the annuli surrounding the suspected leak site.

[0085] Preferably, at least one temperature sensor is located in at least two annuli, more preferably at least one temperature sensor in all annuli each. This way, the temperature of the fluid in each annulus can be measured.

[0086] Preferably, at least one density sensor is located in at least two annuli, more preferably in all annuli. This way, the density of the fluid in each annulus can be measured.

[0087] Preferably, at least one density sensor is located in at least two annuli, more preferably in all annuli. This way, the density of the fluid in each annulus can be measured.

[0088] Preferably, at least one measurement device capable of measuring the liquid level in an annulus is in communication with an annulus. Preferably, at least one measurement device capable of measuring the liquid level in an annulus is in communication with at least two annuli, more preferably with all annuli. These measurement devices can be echo meters (acoustic measurement), ultrasonic transducers and receivers, devices for transmitting, recording and processing modulated pressure waves, or combinations thereof. Device for transmitting, recording and processing modulated pressure waves are preferred, as they allow for an accurate determination of the liquid level in any annulus. These modulated pressure waves may be sound waves. This approach is very different from the echo meter which just uses a gas bubble as the source of a sound. Examples of sound sources may be sonar, and any sophisticated modulation of a low frequency carrier wave and a high frequency signal. Low frequencies travel much further than high frequencies. Preferably, the apparatus is configured so that a modulated pressure wave is produced to provide a continuous detection of liquid levels.

[0089] Preferably, at least one annulus is an injection line, transporting injection gas into the well.

[0090] Preferably, the apparatus also comprises at least two annuli and a plurality of measurement devices, where at least one measurement device per annulus is in communication with the respective annulus.

Method

[0091] In a further embodiment, the problem according to the present invention is solved by a method for determining flow characteristics of produced fluid in a well during production operations using an apparatus according to the present invention, comprising at least the following steps:

a. collecting data from the measurement devices,

b. determine at least one flow parameter of the production fluid using the collected data.

[0092] The at least one flow parameter can be selected from the group instantaneous flow rate (the flow rate at a given point in time), average flow rate (the average flow over a period of time), instantaneous gas flow rate, average gas flow rate, instantaneous liquid flow rate, average liquid flow rate, suspended particle flow rate.

[0093] Instantaneous flow rate (e.g. the flow rate at a given point in time) typically refers to the amount of fluid (liquid or gas) passing through a specific cross-sectional area at a precise moment. Unlike a flow rate averaged over a period of time, the instantaneous flow rate captures the dynamic state of the flow at that particular instant. Engineers can use

measurements of instantaneous flow rates to observe trends and understand the behaviour of a production system, such as fluctuating liquid production in a test separator or the gas flow rate through valves at a specific moment. Techniques like analysing tracer concentration over time or monitoring pump performance can provide insights into this momentary velocity of fluid movement, which can be crucial for production optimization and troubleshooting.

[0094] Average flow rate (the average flow over a period of time) typically refers to the total volume of fluid (liquid or gas) that passes through a specific cross-sectional area divided by the total duration of the time interval over which the flow is measured. Unlike instantaneous flow rate, which captures the flow at a single point in time, average flow rate provides a measure of the overall fluid movement over a defined period, effectively smoothing out any short-term fluctuations or variations in the flow. This metric is crucial for various production engineering calculations and analyses, such as determining the daily or monthly production volumes of a well, assessing the performance of a reservoir over time, and calculating average injection rates in enhanced oil recovery processes like waterflooding. In tracer studies, for instance, average flow rates are used to relate the amount of tracer detected to the volume of fluid that has flowed. Similarly, in gas lift operations, the average gas injection rate and average liquid production rate are important parameters for optimizing the process. Therefore, average flow rate provides a broader perspective on the fluid transport within a production system over a chosen timeframe, which is essential for long-term performance monitoring, economic evaluations, and operational planning.

[0095] Suspended particle flow rate typically refers to the quantity of solid particles moving through a specific cross-sectional area per unit of time while being carried within a fluid (liquid or gas). These particles are not dissolved in the fluid but are dispersed and transported by its movement.

[0096] The at least one flow parameter can be the mass flow, preferably the total mass flow. Mass flow can be measured using mass flow meters (as described above). Total mass flow is the flow through a number of or all meters in parallel. Preferably, as the flow rate reduces, lines with larger range mass flow meters are closed so that the low flow rate can be measured through the meter with the highest sensitivity.

[0097] Wells have a plurality of control options including valves to control gas injection rates and oil production rates, downhole pump flow rates and safety valves. Optimal well performance may be achieved by different combinations of settings of these control elements.

[0098] Preferably, the method according to the present invention also comprises an additional step after determination of the at least one flow parameter:

c. adjust a control option based on the at least one determined flow parameter for optimal well performance.

[0099] The control options can be gas lift valves, valves to control gas injection rates and oil production rates, valves to control downhole pump flow rates, safety valves and/or combinations thereof. The present invention preferably uses the WinGLUE software to determine optimal gas injection and oil production rates based on more accurate measurements of the flow parameters from multiple sensors. The output from WinGLUE informs the operator on new settings for all valves.

[0100] The definition of optimal performance may change during the life of the well and may have different meanings to different operators in different circumstances. Nevertheless, whatever the definition of optimal performance may be at any point in time, there exists a combination of control settings that will give a production profile that is closest to this definition.

[0101] As in all experimental design, a response surface may be determined by measuring the effect on a given output parameter, of changing any or all of the available controls. By reference to the method according to the present invention, an improved response surface for any well may be determined by the use of a plurality of the mentioned measurement devices. The response surface would exist in a Hilbert space of dimension not more than the sum of the number of input and output parameter. The response surface is a mathematical model that characterises the system response to changes in the input parameters, for all possible combinations of input parameters.

[0102] In conventional tracer tests, the tracer concentration is measured using a single downstream measurement device. In this invention, preferably a plurality of downstream measurement devices is employed to improve the characterisation of the tracer dispersion, preferably both in the injection line and in the production line.

[0103] Current gas fingerprinting techniques are poorly defined and fail to consider the specific sensitivities of any sensors to any component. The inventors have developed a proprietary algorithm that allows improved matching in the presence of known measurement inaccuracies. This also allows meaningful comparison between laboratory and field fingerprinting.

[0104] Preferably, step a. comprises a step of determining at least one parameter of the injection gas with the upstream measurement device that is located upstream of the tracer-injection location. This parameter can preferably be the injection rate of the injection gas. The injection rate may be measured using an upstream acoustic sensor and determining the travel time from the tracer injection location and the sensor. By correcting for the speed of sound in a gas under pressure using a compressibility factor, the velocity of the gas can be determined.

[0105] The step of measuring injection rate of the injection gas in the injection line upstream of the tracer-injection location allows a more accurate determination of the gas injection rate and the diffusion characteristics of the tracer

material.

[0106] Preferably, step a. comprises a step of determining at least one parameter of the produced fluid with the at least one downstream measurement device located downstream of the communication points. This one parameter can preferably be e.g. the tracer concentration in the produced fluid. Other sensors can measure the flow velocity in the pipe using acoustic methods in either the audible or ultrasonic ranges, or both. Temperature, pressure and density may be measured using appropriate sensors.

[0107] Measuring the effect of tracer injection in the injection line downstream of the tracer injection location improves the understanding of the diffusion of the tracer.

[0108] Preferably, the tracer concentration is measured at least at two different locations downstream of the tracer-injection location. This allows for a much better understanding of the tracer diffusion characteristics within the injection gas and/or the produced fluid.

[0109] Preferably, the composition of fluids in the production line is measured at a plurality of downstream locations either continuously or periodically. Measurement preferably commences before the injection of any tracer and a stable baseline will be recorded for a plurality of parameters at a plurality of downstream measurement device locations.

[0110] Calculations in prior art typically use average gas-oil-ratios or gas-liquid-ratios in their tracer concentration equations. In the method according to the present invention, preferably an improved calculation for the relative concentrations based on continuous or periodic measurements from a plurality of measurement devices can give instantaneous, rather than average concentrations..

[0111] The present invention uses multiple sensors based on different physics. It recognises that measurements and calculations in prior art often use a single sensor and that this sensor has a sample rate greater than a minute and sometimes much longer. Any rate calculations based on measurements at a low sample rate will tend towards a measurement of an average flow rate, moreover, if concentrations of different components in a composition are measured in different ways the sampling rates and confidence levels for each measurement will be different. In one example of prior art, the nitrogen concentration is estimated from gas chromatography by assuming the unrecorded component of the mixture is nitrogen, since nitrogen is used as the carrier gas.

[0112] To compare measurements from different sensors at different frequencies the present invention determines the correlation length in the time domain of each measurement by constructing a 1D forward variogram. This is used to determine the strength of the linear temporal dependence of each measurement with itself. The second step in the present invention is to construct a 1D forward cross-variogram for each of the measurements to determine the strength of the linear temporal dependence of each pair of measurements. These sets of measurements are combined to create a temporal model of the parameters which is then used to estimate values between sample points.

[0113] This temporal model may preferably be used to increase the resolution of the sampling and to provide limited look ahead capability within the range of the temporal dependence.

[0114] Furthermore, the present invention preferably recognises that the estimation of compositions should be performed in an n-1 dimensional simplex Hilbert space, not a Cartesian space. The present invention preferably computes the temporal model in the simplex corresponding to the mixture or to any sub-composition. The ability to operate on sub-compositions of the mixture is an important preferable characteristic of the present invention since the concentrations of some components may not be known, nor are they important in the determination of flow parameters.

[0115] Preferably, optimal control settings may be determined, and sensitivities of each control option may be determined. These may be displayed as a Pareto chart. A Pareto chart can be constructed to determine the sensitivity of a white box or black box process to a range of input parameters by keeping all parameters except one fixed in mid-range positions and varying the other parameter. This process is preferably performed for each of the parameters in turn and the range of output values is displayed in a horizontal bar chart sorted in descending order of length. This is sometimes called a tornado chart because of its distinctive shape. The input parameter with the greatest effect on the output is the one with the longest bar and the chart is an intuitive method of showing which parameters are important to measure accurately.

[0116] Preferably, optimal control settings for multiple wells sharing the same injection gas are determined such that the net production of oil from these wells is either, largest as measured on a daily basis, or most consistent day-to-day depending on client's operational requirements, These settings include choke and valve settings for each well on the production (output) flow line and the gas injection (input) flow line.

[0117] Preferably, upstream and downstream measurement devices may measure a plurality of different parameters of the fluids including the composition of the fluid, which may be determined using either a spectrometer or chromatograph or any other device capable of measuring chemical compositions.

[0118] Preferably, the measurements for collecting data from the measurement devices are performed continuously or periodically. When performed periodically, preferably the interval between *measurements* is at most 1 minute.

[0119] Preferably, the method according to the present invention also comprises the determination of a rate of injection from the data obtained from a plurality the above-mentioned measurement devices. Measurements from

multiple sources with different physics are cross referenced to improve assessments of accuracy and uncertainty. Injection rates can be determined acoustically upstream using the noise made as the tracer is injected into the flow line, by direct measurement of the mass flow rate using a Coriolis meter or by determination of the duration of injection and the mass difference in the tracer supply tank between the start and end of the injection.

[0120] Preferably, one of the flow characteristics is the rate of any phase or component of multiphase or multi-component flow. Using the difference in speed of sound between phases and components multiple acoustic and ultrasonic measurements may be processed to calculate the proportions of different components and phases.

[0121] Prior art requires operators to check the tracer concentration in a post-survey analysis and pick the start and end points for each returning tracer return. During the review of the method according to the present invention, the inventor found this step to be both labour intensive and inordinately influential on the determination of return volumes. This present invention preferably incorporates a new statistical algorithm that identifies tracer returns and correctly assesses the proportion of tracer that is present in the background, even if the background concentration is changing during the survey. This technique has been shown to improve accuracy of material balance checks on tracer returns (where CO₂ was used as a tracer) even in wells producing more than 60% carbon dioxide from the formation. The new algorithm is able to identify tracer returns, which can operate in situations where the tracer is present in the produced fluid, where this concentration is above 60%, and where the background concentration is changing over time. The algorithm can cross-check against the injected mass of tracer and has shown to be significantly more accurate than manual picking. This invention preferably considers the mass rate profile at the injection point, which the inventor now knows is not a square pulse. Optionally a mass flow meter can be inserted in the tracer injection line to further calibrate the tracer injection mass rate profile. A more accurate profile of the injection mass rate improves accuracy of the method. This technique preferably gives an expected time and an uncertainty range which is useful in quantifying the accuracy of the method. The inclusion of a stochastic flow model provides improved understanding of measurement uncertainty. The number of molecules injected in any given period may be modelled using a Poisson distribution. Using the improved mass rate profile to provide values for the Poisson distribution λ parameter, the molecular tracer injection rate may be modelled. Transport of molecules in the gas stream may then be modelled using a normal distribution. The combination of Poisson distribution and normal distribution is well known to give an exponential distribution so the recorded tracer concentration downstream is expected to have the shape of an exponential distribution with a shape parameter that is a function of the distance from the injection site to the downstream tracer recording location.

[0122] Preferably, the algorithm also takes into account the measurements of the sonic sensors. Preferably, the data collected from the sonic sensors (e.g. the sound that is recorded) originates from the naturally occurring sounds in gas lift operations or from the above-mentioned devices for emitting sonic waves (e.g. the mentioned transducers). The use of devices for emitting sonic waves is that the position of the sonic sensors can then be easily determined via triangulations e.g. of the surface waves in the pipe. Therefore, the field personnel can just attach sensors along the apparatus without the need to exactly note the position. The method according to the present invention therefore can handle sensors in arbitrary locations, which is an advantage for broad spectrum acoustics. In the initialisation phase, arbitrarily located transducers ping in sequence. The earliest arriving pulse at each receiver location is a surface wave travelling at the speed of sound in the pipe which is assumed to be constant (it's a steel pipe). A matrix of times between each transducers may be constructed from the time to receiving the pulse. Dividing each element in this matrix by the velocity of sound in the pipe gives you a distance matrix which is essentially the relative distance matrix for all the sensors so there is no longer a requirement for field engineers to measure the distances between sensors.

[0123] This algorithm preferably allows an improved analysis of the compositional data. The algorithm treats the proportions of phases and components on a simplex Hilbert space rather than an orthogonal cartesian space.

[0124] The mentioned transport algorithm can identify preferred optimal locations for sensors. The system self-calibrates based on its own determination of locations using cylindrical triangulation. Ray tracing algorithms can identify conditions in which the sound waves will be subjected to total internal reflection and therefore become unreceivable on the outside of the pipe. Furthermore, transmitted and reflected energy may be estimated at each sensor location. Recording of background noise determines an expected signal-to-noise ratio at each location so that sub-optimally located sensors can be identified and relocated.

[0125] Also, to better understand the flow of the various fluids using a tracer material, it is important to understand the flow of tracer material when injected into the injection gas.

[0126] Prior art assumes a square pulse of tracer is injected into the injection gas line. The actual profile is quite different with a significant spike in mass injection rate once the valve is opened. The mass flow rate slows to a plateau until the pressure in the tank is low enough for the liquid CO₂ to become a gas for which the mass flow rate declines rapidly until the pressure in the tank is the same as the flowline (see Figure 2).

[0127] Preferably, in the method according to the present invention, data is presented to the user of the method, preferably in the form of a dashboard. The dashboard may display fluid composition in real-time allowing user to view compositional changes during the test. This can be achieved because at least some of the employed measurement

devices can deliver data in real-time or near-real-time.

Further Embodiments

[0128] The problem according to the present invention is solved in as further embodiment of using the apparatus according to the present invention to determine the leak rate between the injection line and at least one neighbouring line.

[0129] The problem according to the present invention is solved in as further embodiment of using the apparatus according to the present invention to measure the flow rate of the production fluid in the production line.

Figures

[0130] In the following is described example embodiments with reference to the accompanying drawings, wherein:

Fig. 1 shows an apparatus for producing fluid from a well using gas lift technique

Fig. 2 shows the apparatus used for leak detection

Fig. 3 shows an array of measurement devices

Fig. 4 shows a mass injection rate profile

Fig. 5 shows repeated measurements using the single high-precision measurement device such as a pressure sensor and an array of measurement devices such as pressure sensors

Fig. 6 shows repeated measurements using the single measurement device such as a high-precision pressure sensor and an array of measurement devices such as an array of pressure sensors.

[0131] The figures should not be construed as limiting the scope of the claims. The figures serve to show the invention in concrete examples so that the skilled person is able to understand how to work the invention.

[0132] Figure 1 shows an example of an apparatus according to the present invention as used in gas lift operations to produce oil from a petroleum well. This figure shows the following: an injection gas source 10, a tracer source 12, in injection gas control valve 14, a tracer inflow control valve 16, A-annulus as the injection line 18, a tracer inlet 19, upstream measurement devices 20 upstream of the tracer injection inflow control valve 16, upstream measurement devices located between the tracer-injection location and the communication points 22, downstream measurement devices 24, a production line output 26, communication points 28 (e.g. gas lift valves), a packer 30, perforation 32, a production casing 34, an intermediate casing 36, a surface casing 38, a conductor casing 40, the wellhead 54, the production line (tubing) 56, cement 58, and the reservoir 62.

[0133] A tracer can be available at a source 12 and may be introduced at a rate controlled by the tracer inflow control 16 into the injection line 18.

[0134] Parameters of the injection gas and the mixture of injection gas a tracer can be measured by upstream sensors 20 and 22, and downstream sensors 24.

[0135] The mixture of injection gas and tracer can travel down the well and may be controlled by a plurality of gas-lift valves 28.

[0136] The producing interval is isolated using a packer 30 and the connectivity between the well and formation may have been improved by perforations 32.

[0137] Oil from the formation is mixed with the injection gas to reduce its density so that it will flow more easily along the production line to the surface production line output 26.

[0138] A plurality of measurement devices such as sensors 20, 22 and 24 can be installed e.g. at surface on the production line 56 to measure parameters of the fluid mixture.

[0139] Fig. 2 shows the apparatus as used for leak detection, The figure shows the packer 30, perforation 32, production casing 34, intermediate casing 36, surface casing 38, conductor casing 40, an A-annulus (used as the injection line) 42, a D-annulus 42, a C-annulus 44, a B-annulus 46, an A-annulus 48 (which is used as the injection line 18), the wellhead 54, the production line (56, tubing), cement 58, the reservoir 62 (not belonging to the apparatus, of course), flow lines from each annulus 66 with arrays of measurement devices 64 in each flow line, and flow valves 70 to control the flow in the annuli.

[0140] This figure shows the configuration of the apparatus for the determination of volume and composition of gas leakages. For clarity only a single annulus, the B annulus 46, is discussed. The liquid level in the B annulus 46 can be

measured continuously using modulated pressure waves, rather than the Echometer pulse used by prior art. Flow can be measured using multiple flow meters in the control unit 52, with different ranges and precisions. Pressure, density and temperature are measured continuously using the array of measurement devices 64 in each annulus. The pressure difference between annulus A and annulus B is reduced to determine leakage from A into B or vice-versa, or the pressure difference between annulus B and annulus C may be reduced to determine the leakage from C into B or vice-versa. The control unit 72 can be capable of monitoring pressure differentials between adjacent annuli and analysing these with data from the array of measurement devices and mathematical models of leak characteristics.

[0141] This figure 2 can also be used to illustrate the determination of liquid flowing between annulus B 46 and annulus C 44. The change in liquid levels (LLB and LLC, where LLB is the liquid level in the tubing and LLC is the liquid level in the casing or annulus) can be determined from the continuous modulated pressure waves. The control unit 72 could also monitor changes in pressure, density and temperature in the gas phase as the apparent liquid leak may also include a gas phase that can be determined by reducing the pressure differential between B and C and monitoring the flow rate response to the reducing pressure differential. Composition of the mixture of gases may also be determined either in real-time using a fluid analyser or by sampling for laboratory analysis.

[0142] This figure 2 can also be used to illustrate fluid ingress from the formation at location LFS (leakage flow site). Fluid moves through the porous rock and may enter annulus D 42 through poor cement and fractured casing or into annulus C 44 through poor cement, or both. Change in liquid level or pressure in annulus D or C or both can be observed and analysed e.g. in the control unit 72.

[0143] Fig. 3 shows an array of measurement devices 64 (e.g. a sensor assembly) as it is e.g. used in the flow lines 66 connected to each of the annuli 42, 44, 46 and 48. This figure shows the fluid analyser 17 such as Raman spectrometer (as a special form of a measurement device 68), the flow valves 70 sitting in the flow lines 66, pressure sensors 50 (as a special form of measurement devices 68), wired or wireless measurement devices 68 (such as flow meters or acoustic sensors), where some of the measurement devices 68 can also be wireless gas cards to measure gas concentration 74. The measurement devices 68 are controlled by a control unit 72. This figure 3 also shows the pressure sensors 50 as well as the flow meters 52. The location of the array(s) of measurement devices 64 can be seen e.g. in figure 2.

[0144] Figure 4 shows the mass injection rate of tracer material such as carbon dioxide into an injection gas such as methane. The mass rate in kg/h (y axis) is plotted against time. It becomes clear that the injection of tracer material does not result in a "square pulse", which the prior art assumes to be correct. This leads to the models of the prior art to be incorrect.

[0145] Observing this, the inventor of the present invention saw the need to get a very detailed understanding of the flow of the various fluids in gas lift operations when using tracer material.

Examples

[0146] The following examples illustrate the invention. The examples should not be construed as limiting the scope of the claims. The figures serve to show the invention so that the skilled person is able to understand how to work the invention. All following examples and described features are preferred features.

[0147] When asked to improve the accuracy of measuring a physical quantity in a petroleum well, or in the pipeline infrastructure around the well, a skilled person would consider the following options:

1. Purchase a more accurate sensor
2. Take more measurements and average them

[0148] One core concept of the invention is that the inventors were able to improve the accuracy not by buying a more expensive and accurate sensor but by buying more cheaper sensors. One core concept of the method according to the invention is rather than taking the average of measurements, the inventors used resampling techniques that allow the combination of multiple sensors with different accuracies and drifts which becomes self-correcting and is robust to individual sensor failure.

Some theoretical background:

[0149] The inventive method used a resampling technique to aggregate information from different sources. This sampling technique is used extensively in the method. Wherever measurements are needed, multiple sensors are used. As an example accurate measurements of pressure in each of the annuli is required during the bleed-down stage of the sustained pressure test. The apparatus preferably has multiple pressure sensors in each annulus located close together to ensure that their locations lie within a region of common support and the pressure within this region is

considered spatially stationary or invariant with location. Now, temporal stationarity needs to be considered, but this is challenging as the inventors are measuring changes of pressure in time. However, if the time window is sufficiently small the inventors can assume temporal stationarity. In each survey the method will assess a suitable sample frequency such that the assumption of temporal stationarity is met.

[0150] An arrangement of sensors within the same spatial and temporal support means that they are all measuring the same phenomena. Now assume that the sensors are using different techniques to measure pressure and have different accuracies which may be modelled by a Gaussian distribution with a mean close to zero and some variance that is related to the accuracy. A sample taken from sensor, s ; $p_{i,s}$ may be denoted by

$$p_{i,s} = N(\mu_s, \sigma_s) \quad (1.0)$$

[0151] The inventors can overcome sampling errors in a single sensor by averaging the samples;

$$\langle p \rangle \approx \frac{1}{n} \sum_{i=1}^n N(\mu_s, \sigma_s) \quad (2.0)$$

[0152] Alternatively, the inventors could define a set of n measurements at a single sensor, that the skilled person would measure, using this notation

$$\{P_{i,s}\}_{i=1}^n \text{ with } P_{i,s} \stackrel{iid}{\sim} N(\mu_s, \sigma_s)$$

[0153] The inventors can improve the estimate of the expected value if, instead of simply taking the mean of this set of measurements, the inventors take subsets of k samples from the n measured values in our set, S .

[0154] The number of k -subsets may be represented as

$$\binom{n}{k}$$

using a notation that is analogous to the binomial coefficient which counts k -subsets. This expression can also be given in terms of binomial coefficients:

$$\binom{n}{k} = \binom{n+k-1}{k}$$

[0155] If the inventors now compute an expected value by computing the means of each subset, and then take the means of these means, not only does our estimate of the expected value tend towards the true mean, but the variance narrows, which is analogous to the accuracy of the measurement increasing.

[0156] So, whilst a skilled petroleum engineer would take the mean of the measured values from a single sensor, the inventive method and apparatus uses multiple sensors and the resampling technique to improve the accuracy of measured values, irrespective of the sensor type.

[0157] This technique can be shown, using the Central Limit Theorem, to work irrespective of the underlying distribution of the readings from each sensor, so if a particular sensor in the array returns values according to a uniform distribution given by the expected value and the bounds from measured tolerances, $\pm T$, the distribution of the sampled subsets from S will be a Gaussian distribution. In this case the inventors would rewrite eq. 1.0 as

$$p_{i,s} = X \sim f_X(x) \quad (3.0)$$

[0158] The method is suitable for heterogeneous sensors in which the expected value from each sensor

$$\{P_{i,s}\}_{i=1}^n \text{ with } P_{i,s} \stackrel{iid}{\sim} F \quad (4.0)$$

where F represents any continuous distribution, not necessarily a Gaussian distribution. The math described above is consistent with this extension with the predefined conditions of spatial and temporal stationarity.

[0159] A single high-precision sensor may be simulated using a distribution with the mean being the expected measured value and the variance being very low. Similarly, an array of low-precision sensors may be simulated with means corresponding to the expected value plus a drift term to account for sensors that regularly read high or low. The inventors will ignore the fact that high precision sensors can also suffer from drift for the moment.

[0160] Figure 5 shows the tolerance and drift for a high precision sensor (cross), and a number of less precise sensors used in an array of heterogeneous sensors (circles).

[0161] Figure 6 shows repeated measurements using the single measurement device (crosses) such as a high-precision pressure sensor and an array of measurement devices (circles) such as an array of low-cost, low-accuracy, e.g. pressure sensors.

[0162] Correction for Variable Drift in Sensor Arrays: For a single sensor a skilled person may create a mathematical model that captures the uncertainty in the measured values using a standard techniques.

$$\mathbf{d} = \mathbf{m}(\boldsymbol{\theta}) + \boldsymbol{\epsilon} + \boldsymbol{\delta} \quad (5.0)$$

where

$\mathbf{d} = [d_i] \in \mathbb{R}^N$ are the measured data

$\boldsymbol{\epsilon} \sim N(\mathbf{0}, \sigma_{\epsilon}^2 \mathbf{I})$ is the random vector of measurement errors

$\boldsymbol{\theta} \in \mathbb{R}^M$ are the parameters governing the computer model $\mathbf{m}(\cdot)$

$\boldsymbol{\delta} \sim N(\mu_{\delta}, \Sigma_{\delta})$ is an additive model inadequacy parameter that takes into account the model output not being equal to the true value of the measured variable

[0163] The parameters controlling this model can be calibrated using Bayes' Theorem

$$\pi(\boldsymbol{\gamma}|\mathbf{d}) \propto p(\mathbf{d}|\boldsymbol{\gamma})\pi_0(\boldsymbol{\gamma}) \quad (6.0)$$

where

$\boldsymbol{\gamma} = [\boldsymbol{\theta}, \mu_{\delta}, \hat{\xi}]$ and $\hat{\xi}$ is a vector of model parameters depending on the form of the model inadequacy covariance matrix Σ_{δ} $p(\mathbf{d}|\boldsymbol{\gamma})$ = the likelihood which provides the means for updating the model with observed data

$\pi_0(\boldsymbol{\gamma})$ = the prior distribution which represents what is known about $\boldsymbol{\gamma}$ before the data become available

[0164] Note that in this notation $\pi(\cdot)$ are the pdfs relating to non-observable variables, and $p(\cdot)$ those relating to observable variables.

[0165] Using this standard model once the elements of $\boldsymbol{\gamma}$ have been calibrated, they can be fed to the statistical model to predict the measurements d at a new $\boldsymbol{\theta}$ (after all the model parameters have been fixed e.g. to their posterior mean value) by computing the posterior predictive distribution:

$$p(\bar{d}|\mathbf{d}) = \int p(\bar{d}, \boldsymbol{\theta}|\mathbf{d})d\boldsymbol{\theta} = \int p(\bar{d}, \boldsymbol{\theta})\pi(\boldsymbol{\theta}|\mathbf{d})d\boldsymbol{\theta} \quad (7.0)$$

[0166] Which the inventors would read as the probability of the measured value of a variable, $\bar{d}$, being the actual value of the variable at the point in space and time at which it was measured, given the measured value, d . For a perfectly accurate measurement this would be 1.

[0167] The current best practice has some flaws which are addressed in the method.

[0168] Non-Gaussian: Eq 5.0 contains terms for the measurement errors, $\boldsymbol{\epsilon}$ and the inadequacy parameters, $\boldsymbol{\delta}$, which are both assumed to be normally distributed $N(\mu, \sigma)$. Whilst the assumption that measurement errors follow a Gaussian distribution is common and recognised by skilled engineers, closer inspection of errors often indicates departures from normality that may be significant. For example, measurement errors in photon counts from scattering sensors or radioactive decay follow a Poisson distribution. Similarly, the assumption that the inadequacy parameter follows a Gaussian distribution is convenient, but not always appropriate. The extraction of signals from sonic sensors need to develop sophisticated models of the noise functions corresponding to the inadequacy parameter in eq. 5.0.

$$\mathbf{d} = \mathbf{m}(\boldsymbol{\theta}) + \epsilon + \delta \quad (8.0)$$

where

$\mathbf{d} = [d_i] \in \mathbb{R}^N$ are the measured data

$\epsilon \sim f_\epsilon(x)$ is the random vector of measurement errors

$\boldsymbol{\theta} \in \mathbb{R}^M$ are the parameters governing the computer model $\mathbf{m}(\cdot)$

$\delta \sim f_\delta(x)$ is an additive model inadequacy parameter that takes into account the model output not being equal to the true value of the measured variable

[0169] The parameters controlling this model can also be calibrated using Bayes' Theorem (eq.6.0) and the form of the posterior predictive distribution is still given by eq.7.0.

[0170] Multiple sensors: The apparatus can comprise multiple heterogeneous sensors, measuring the same property using different physics at different locations in space and time subject to the stationarity requirements discussed above. This allows the inventors to replace the measurement model defined in eq.5.0 with one that represents a combination of measurements from multiple individual sensors.

[0171] For a single sensor, s , the model is the same, though ϵ and δ are not restricted to values that are Gaussian distributed.

$$\mathbf{d}_s = \mathbf{m}_s(\boldsymbol{\theta}_s) + \epsilon_s + \delta_s \quad (9.0)$$

[0172] And the expected value would be

$$\begin{aligned} \hat{\mathbf{d}} &= \sum_{s=1}^S \frac{\mathbf{d}_s}{\lambda_s} \\ &= \sum_{s=1}^S \frac{(\mathbf{m}_s(\boldsymbol{\theta}_s) + \epsilon_s + \delta_s)}{\lambda_s} \end{aligned} \quad (10.0)$$

where

λ_s is the weight assigned to sensor s in the sensor array S containing N sensors, and

$$\sum \lambda_s = 1.0$$

[0173] The challenge is then to determine appropriate values for the weights, λ_s .

[0174] The method uses a standard Bayesian learning algorithm and assumes uniform prior values for the weights,

$$\lambda_s = \frac{1}{N} \quad \forall s \in S$$

[0175] Non-stationary: In practice the requirement for space-time stationarity is restrictive. The method further extends the utility of multiple sensors to non-stationary situations. As an example measurements of pressure at different locations along a pipe may vary with distance, and measurements of pressure at the same location may vary over time.

[0176] In the non-stationary case the model from eq.9.0 becomes

$$\mathbf{d}_s(z, t) = \mathbf{m}_s(\boldsymbol{\theta}_s(z, t)) + \epsilon_s(z, t) + \delta_s(z, t) \quad (11.0)$$

[0177] In which $\boldsymbol{\theta}_s(z, t)$, $\epsilon_s(z, t)$, $\delta_s(z, t)$ are random fields whose non-linear spatial dependence is determined by the method using standard spatial statistical techniques.

Specific Examples

[0178] The apparatus and method according to the invention may be used in a variety of settings in a petroleum well to determine the values of dynamic parameters. The theory above, and the examples discussed in brief, give insights into the novelty of the invention. More specific examples of the use of the invention for specific cases are given here.

Redundant Measurement Devices

[0179] In spatial statistics, a spatial support refers to the size and shape of the area or volume or range or time over which a variable of interest is measured or observed. This is important in all measurements as it indicates the area or volume or range of time over which the measurement has any validity.

Temporal support:

[0180] A single measurement of the barometric pressure is unlikely to be constant for the whole day and would not, on its own help with determination of the likelihood of a storm. In the case of weather prediction more frequent measurements would be necessary.

[0181] The apparatus preferably comprises multiple continuously recording and periodic sensors with high sample rates. This allows the method to select the most suitable subsets of measurements to provide the correct temporal support for the calculations and to process this data in a way that improves the information content of the recorded data. Taking slow and more precise measurements may not be the most accurate approach if the temporal support is not aligned with the calculation objectives.

Spatial support:

[0182] A single measurement of elevation may be sufficient to predict height above sea level in the Netherlands, but would be unsuitable in the Alps, because the underlying parameter has a different spatial model in the two regions, and therefore a different spatial support is needed.

[0183] The apparatus preferably deploys multiple sensors at multiple locations so that the method can determine an appropriate spatial model. Once this spatial model has been analysed, the sensors may be polled based on the appropriate support. In the example, if the model is like the Netherlands, then data from the sensors may be averaged whereas if the model is like the Alps data from the sensors needs to be interpolated.

Leak Detection

[0184] The apparatus and method of the invention is used to measure dynamic parameters of a petroleum well during leak detection or sustained casing pressure tests. In this case sensor arrays are deployed in one annulus, or any combination of annuli, or all annuli (the survey annuli).

Increased Accuracy of Pressure Measurements During Bleed-Down:

[0185] The apparatus, having been installed in the survey annuli, is turned on and the software will contact each sensor in turn to collect initial values. Individual unresponsive sensors may be ignored if sufficient redundancy exists. Distances between sensors are recorded by the operator and entered into the software. Sensors with clocks are synchronised. The distances between sonic sensors connected to the same pipe is validated using by initiating surface wave at any sensors, recording the travel time to all the other sensors and then using a triangulation algorithm on the surface of a cylinder. This process may be repeated for other sonic sensor locations to build an accurate triangulation of the sensors, and an associated distance matrix which is used to correct for non-stationarity in location.

[0186] The needle valve is partially opened to ensure a long bleed down and the sensor arrays record continuously. The Bayesian learning algorithm will continue to update the weights of the measurements from individual sensors based on their cosine distance from the computed value. Individual sensors that fail will be assigned a zero weight, sensors that appear to drift will have a drift correction assigned.

[0187] This method overcomes issues with individual sensors, whether they are drifting out of calibration, or the value is outside the specified range for the sensor, or they fail completely. Moreover the sampling procedure reduces the variance in measurements and provides greater accuracy through redundancy.

Arbitrary Locations in Space or Time:

[0188] Positioning of sensors and timing of measurements in the sensor array will affect the reading of individual sensors in the non-stationary case since, $m_s(\rho_s(z, t))$ is no longer constant. Challenges for field engineers are practical, since it is not always possible to place sensors wherever you want, or at least it is expensive and time-consuming to place them in ideal locations.

[0189] The apparatus and method according to the invention support arbitrary placement of individual sensors and arbitrary measurement intervals through the corrections that have been determined from the spatio-temporal model of the random fields. However, the method recommends non-uniform spacing in space and time for individual sensors in order to avoid spatial and temporal aliasing of random fields with any underlying periodicity.

Optimal Locations in Space or Time:

[0190] The apparatus and method according to the invention provides guidance on optimal locations and measurement intervals based on spatial analysis of the random fields and any potential periodicity. As in the arbitrary location case, uniform spacings may present aliasing issues if these are harmonics of any identified periodicity. In general the method recommends non-uniform sampling techniques, such as Golomb rulers in space and time.

More Accurate Determination of Mass Flow Rate:

[0191] The leak detection test relies on accurate measurement of low flow rates in all of the survey annuli. In this case the apparatus uses a sensor array consisting of mass and volume flow meters, pressure and density sensors. The advantage of the sensor array over a single high-precision mass flow meter is not just in redundancy and protection from instrument failure during the survey, but, as described above, the higher accuracy gained from processing multiple measurements and averaging subsets of the set of measurements that have been randomly selected with replacement.

More Accurate and More Continuous Determination of Liquid Levels in Annuli:

[0192] The leak detection test also needs accurate measurements of the liquid level in all of the survey annuli in the well. Current best practice is to use an Echometer survey during the test. This measurement may be repeated during the test but is not generally performed periodically or continuously.

[0193] The apparatus contains an array of pressure sources with at least one source in each of the survey annuli. These pressure sources are activated in sequence during the test and provide modulated pressure pulses into each of the survey annuli for the duration of the test.

[0194] The apparatus also contains an array of pressure sensors with multiple sensors in each of the survey annuli. Measurements from each sensor array are processed using the theory described above to average subsets of the set of measurements at each measurement time that have been selected randomly with replacement. The complete dataset from all arrays provides an accurate picture of the liquid levels in all of the survey annuli during the leak test and it's used with the mass flow measurements and the bleed-down, constant pressure and bleed-up pressures together with a standard mathematical model to determine the leak rates between each of the survey annuli.

Well Tracers

[0195] Tracer returns are usually measured with a gas sensor downstream, however, if we know something about the fluids at the location where the tracer is injected, we can predict the time and shape of the tracer returns. Competitors claims to measure "a parameter of flow in a fluid" using a dilution technique, but the inventors have successfully argued that this prior art is weak. In particular, it fails to consider anything about the conditions at the injection site. The inventors have models of the mass rate of tracer gas into a pipeline, which the inventors use to predict the tracer shape downstream, but the inventors also need to measure the velocity of fluid in the pipe at the injection location. Engineers tell us that you can hear a whistle as the CO₂ enters the pipe. By putting acoustic sensors upstream and downstream of the injection location the inventors can determine the velocity of the fluid by the difference in the time the whistle is heard or the change in apparent frequency of the whistle using the Doppler effect.

[0196] Predictions of the tracer returns are straightforward. In the ideal case the inventors consider molecules of tracer entering the gas line using a Poisson distribution as a reasonable estimate of discrete events per unit time. Once the tracer molecules are in the gas line, they will travel downstream, subject to some random interactions which will cause a dispersion in arrival times following a normal (Gaussian) distribution. There is an analytical solution for a combination of Poisson and normal distributions which is the Gamma distribution. The shape term is dependent on the

distance (as would the variance of the Normal distribution). So, for a given distance downstream we can predict the time, and the shape of the return.

[0197] Using similar techniques the inventors can assess the leak rate using a Poisson distribution and use this with the idealised return to determine the leak rate and location.

[0198] The apparatus and method of the invention may be used to measure dynamic properties of the well during a well tracer test, which is designed to determine the performance of a gas-lift well. Multiple heterogeneous sensor arrays are deployed in this case; around the site of the tracer injection on the gas injection line, along the production line at more than one location. The apparatus may optionally include multiple compositional sensors each of which has at least 2 of the following sensor types; gas chromatograph, near-infrared spectrometer, Raman spectrometer, gas cards for individual gas components expected to be present in the production line.

Improved Determination of Fluid Velocities at Tracer Injection Location:

[0199] Both the dilution and travel time methods for the determination of dynamic parameters in well tracer tests are known to be sensitive to the mixing of the tracer at the injection location. In general, most skilled engineers would agree that the currently available apparatus and methods do not measure anything at the injection site, except sometimes a mass flow is placed in the tracer injection line to measure the rate of injection of the tracer. Very little is known about the state of the gas injection line.

[0200] To accurately determine the velocity of fluid in the injection line at the location where the tracer is injected, the apparatus uses a heterogeneous sensor array placed around the injection location with sensors arranged both upstream and downstream of this location. The sensor array will include multiple sonic sensors upstream and downstream and these may operate in audible, ultrasonic and infrasonic ranges. Additional sensors in the array may include pressure, temperature and density sensors. The sonic sensors record passive sound generated at the site of the tracer injection by vortex shedding at the inlet valve.

[0201] The velocity of the fluid in the injection line may readily be determined accurately using the apparatus and method of combining measurements from multiple sensors in the non-stationary case where the random fields associated with the ε and δ terms in the model are used by the software to correct for non-stationarity. These corrections, which are required to ensure that all measurements are in phase are related to the location of the sensor and the velocity of the fluid.

Improved Modelling of Tracer Pulse:

[0202] The apparatus and method ensure accurate determination of dynamic flow parameters at the injection site, including the mass rate of tracer injection and fluid velocity in the injection line.

[0203] The method uses a statistical model to determine the shape of the tracer pulse at any downstream location. The mass rate of tracer injection is assumed to be a Poisson distribution, $P(k(t))$, with varying values of the k depending on the mass rate at time t . Once the tracer is in the injection line, the time it takes to travel to any location downstream, x , may be modelled as $N(f(x), \sigma)$. This combination of Poisson and normal distributions is known to be a Gamma distribution whose parameters are readily determined from the underlying Poisson and normal distributions.

[0204] The theoretical model of tracer pulse shape at any downstream location may be used in mass balance calibration of losses in the injection gas and total mass of multiple tracer returns. This in turn leads to a more accurate assessment of the performance of the gas lift system.

Fluid Fingerprinting

[0205] Fluid fingerprinting is a technique to match compositions of a sampled fluid against a library of possible reference fluids that have been accurately measured in a laboratory. The conventional approach considers the gas contents in each sample as a vector and the closest match would be the reference fluid shortest vector distance to the sample.

[0206] The current technique fails for a number of reasons:

1. The sampled fluid may not have been analysed for all components
2. The distance calculation does not consider that the underlying parametric geometry is a non-Euclidean space
3. The sampled fluid may have changed its composition between the formation and measurement location either due to distance effects or temporal effects.

[0207] All of these limitations of the prior art and current best practice may be overcome by the method.

Compositional Data Analysis (CoDA).

[0208] CoDA techniques were developed in the 1980s but are only recently gaining acceptance in the same way that Bayesian statistics is now commonplace despite being invented 250 years ago and contemptuously dismissed by the statistics establishment as recently as the 1970s. See Alenazi (2023) for a review of the technique. The method for fingerprinting uses CoDA extensively.

[0209] As a simple example consider two vectors representing readings from three sensors recording H₂S, CO₂, C₂H₆ concentrations at time t_1 : (1.6, 2.4, 4.0) and at time t_2 : (3.0, 4.5, 7.5). How is this interpreted? Should we be concerned that the concentration of H₂S is increasing? The ratios of these concentrations remain constant so it's more likely that the density of the gas mixture has increased.

[0210] Let us now imagine a third measurement at t_3 : (2.0, 2.0, NaN) where the ethane sensor has failed. What can we now infer? Either the proportion of H₂S is increasing, or the carbon dioxide is falling. We can clearly state that the hydrogen sulphide concentration is increasing relative to the carbon dioxide. The key to comparing mixtures is to consider their scale invariance due to the fact that the sum of the components is known. Converting measurements of the individual components using a log ratio transformation is the first step in compositional data analysis.

[0211] All this is only now possible with the apparatus according to the present invention.

[0212] Parameter Space: It is important to recognise that this transformed data is no longer in a Euclidean vector space but a Hilbert simplex geometry. The allowable values for 3 independent variables with values between 0 and 1 in Euclidean vector space occupy a unit cube. The allowable values for 3 independent variables of compositional data with values between 0 and 1 in a Hilbert simplex occupy a planar triangle. If there are n components in the composition the allowable values exist in a Hilbert simplex geometry of order $n-1$. The method uses a transformation of compositional measurements from Euclidean vector space to Hilbert simplex space to avoid problems associated with spurious dependence.

[0213] Sub-compositional coherence: Furthermore, the method uses sub-compositional coherence to analyse subsets of the whole composition, recognising that not all components of the mixture have been measured, and extends this concept, using Bayesian and frequentist techniques to handle different sensitivities to different component sensors.

[0214] Compositional variation spatially and temporally: this method uses extensions to the analysis of compositional data which include the development of spatio-temporal models to predict the concentrations of individual components at different locations in the system and at future times. These techniques are valid for incomplete sets of compositional measurements using the mathematics of sub compositional coherence. A description of the theory is given in Pawlowsky-Glahn and Egozcue (2022). The method uses proprietary code that combines multiple and redundant sensor information into incomplete compositional vectors. Matching these incomplete vectors with fluids of known composition then relies on the determination of distance between vectors in a non-orthogonal Hilbert simplex space.

[0215] The apparatus according to the invention may include heterogeneous sensor arrays with sensors that measure individual components or multiple components. A skilled engineer has a reasonable expectation that the accuracy of compositional measuring devices has the same accuracy for all components in the composition. A novel feature in the apparatus and method is that this assumption is not necessary. Measurements from arrays of sensors, measure different components in the composition without any assumed accuracy. The method of taking multiple subsets with replacement from the set of measurements provides greater accuracy and repeated measurements provide the prior distributions for a standard Bayesian learning algorithm to continuously update the weights assigned to each measurement.

[0216] Moreover the method transform all compositional data into a simplex Hilbert space to allow partial matching of compositional samples using sub-compositional coherence. In essence this means that any measured subsample (a n -component composition in an m -dimensional composition where $m > n$) may be represented as an n -dimensional planar surface in an m -dimensional Simplex Hilbert space. All points on that planar surface will have the same subsample composition and are candidates for a fingerprint match.

Determination of Liquid Levels

[0217] At source location the apparatus produces periodic broad frequency pressure pulses or continuous broad frequency signals that are amplitude, frequency and/or phase modulated. These pulses and signals are rich in their frequency content. The acoustic response can be continuously recorded from a plurality of sensors at multiple receiver locations.

[0218] The method processes the recorded signals firstly by deconvolution and demodulation of the input pulse or

modulated signals with the recorded signals to get a series of δ functions. These are rarely pure δ functions but have a finite mean width at half height which may be processed to determine acoustic dispersion coefficients.

[0219] By computing the time between peaks, the depth location of reflection events may be determined. Early peaks often represent known features in the casing and may be used to calibrate the speed of sound. The deepest strong reflection will be at the gas-liquid interface. The method records continuously to monitor the liquid level which changes over time and is used to determine gas volumes in the bleed-down, constant pressure and bleed-up stages of the sustained casing pressure test.

[0220] The method relies on redundancy in the source-receiver locations to improve signal-to-noise ratio once corrected for source-receiver distances using a similar technique to seismic stacking and moveout corrections.

Bleed down:

[0221] The method relies on accurate and continuous measurement in all annuli during bleed down. Recent work by Kazemi and Wojtanowicz (2022) suggest that analysis of the bleed down stage of the mandatory sustained casing pressure test (SCP) is sensitive to the operation of the needle valve controlling the pressure, and the time between pressure measurements. Improper measurement and control during the bleed down stage can significantly change values of the minimum bleed down pressure, and the maximum twenty-four-hour build-up pressures, which are the key outputs from this test.

[0222] The method according to the present invention overcomes these issues using multiple measurement devices such as an array of measurement devices (e.g. sensors) running continuously with frequentist sampling techniques to improve accuracy and Bayesian techniques to control sensor drift.

Constant pressure:

[0223] The constant pressure flow stage is the period in which constant pressure is observed at the casing head at the end of pressure bleed down. The apparatus according to the present invention preferably has multiple pressure and flow sensors and the method statistically aggregates these to ensure continuous and accurate measurements of these parameters during the constant flow stage.

[0224] Different mathematical models have been developed for analysing different conditions; flow in the annulus with a liquid column above the top of cement, flow through an annulus that is cemented to the top, and for an annulus containing only a liquid column. Some models are available in the public domain for these cases. The method considers combinations of these conditions with the possibility of different models in each annulus. One advantage of the method according to the invention is that all annuli are evaluated together.

Bleed up:

[0225] Determination of the final build-up pressure after a 24 hour period can be challenging, and is also expensive since the well is not on production. Moreover, it has become apparent to skilled practitioners that the final build-up pressure may be affected by the bleed-down pressure.

[0226] If the valve is closed before the minimum bleed-down pressure is reached, then the maximum build-up pressure may be obtained fairly accurately. However, if the bleed-down stage waits until the minimum bleed-down pressure is established, the bleed-up stage approaches the maximum build-up pressure very slowly, often exceeding the scheduled 24-hour duration of the test. Current best practice is to repeat the test once with an early shut-in during the bleed-down to give the most accurate build-up pressure, and again with a delayed shut-in for the bleed-down stage to get the most accurate bleed-down pressure.

[0227] The apparatus according to the present invention can comprise multiple continuously monitored sensors which significantly improve accuracy and compensate for individual sensor drift or failure. The method therefore allows improved forward prediction which then allows the minimum bleed-down pressure to be determined accurately thus allowing the operator to shut the valve early and measure an accurate build-up pressure.

Reference Numbers

[0228]

10 Injection gas source

12 Tracer source

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	14 Injection gas control valve
	16 Tracer inflow control valve
5	17 Fluid analyser - (e.g. gas chromatograph, Raman spectrometer or gas sensors)
	18 Injection line = A-annulus
	19 Tracer inlet
10	20 Upstream measurement devices
	22 Upstream measurement devices located between the tracer-injection location and the communication points
15	24 Downstream measurement devices
	26 Production line output
	28 Communication points (e.g. gas lift valves)
20	30 Packer
	32 Perforation
25	34 production casing (casing)
	36 intermediate casing
	38 surface casing
30	40 conductor casing
	48 A-annulus
35	46 B-annulus
	44 C-annulus
	42 D-annulus
40	50 pressure sensor
	52 flow meter
45	54 Wellhead
	56 production line (e.g. tubing)
	58 cement
50	60 hanger
	62 reservoir
55	64 arrays of measurement devices
	66 flow lines from each annulus

68 measurement devices (wired or wireless)

70 flow valves

72 Control unit (e.g. for flow meters and gauges and control for each measurement device)

74 wireless gas card (to measure gas concentration, e.g. CO₂)

Claims

1. An apparatus for measuring parameters of a petroleum well, comprising:

- a. a production line (56), transporting production fluid out of the well,
- b. at least one annulus (42, 44, 46 or 48) around the production line (56),
- c. at least one upstream measurement device (20 or 22) configured to determine at least one parameter of the fluid in the at least one annulus (42, 44, 46 or 48), and
- d. at least one downstream measurement device (24) configured to determine at least one parameter of the produced fluid.

2. The apparatus according to claim 1, **characterized in that** at least one annulus (42, 44, 46 or 48) is an injection line (18), transporting injection gas into the well.

3. The apparatus according to any of the preceding claims, **characterized in that** there are communication points (28) between the production line and the at least one annulus (42, 44, 46 or 48).

4. The apparatus according to any of the preceding claims, **characterized in that** the upstream and downstream measurement devices (20, 22 and/or 24) include at least 2 sonic sensors and at least one pressure sensor.

5. The apparatus according to any of the preceding claims, where a tracer injection communication point is located along the at least one annulus (42, 44, 46 or 48), so that a tracer substance can be introduced into the annulus (42, 44, 46 or 48), **characterized in that** at least three upstream measurement devices (22 and/or 20) are located within at most 5 m of the tracer injection communication point, where at least one of these upstream measurement devices is a flow meter (52) and at least two of these upstream measurement devices are sonic sensors.

6. The apparatus according to any of the preceding claims, **characterized in that** it comprises 4 to 100 upstream and downstream measurement devices (20, 22 and/or 24).

7. The apparatus according to any of the preceding claims, **characterized in that** 10 to 99% of the upstream and downstream measurement devices (20, 22 and/or 24) are sonic sensors.

8. The apparatus according to claim 7, **characterized in that** the sonic sensors are acoustic sensors or ultrasonic sensors.

9. The apparatus according to any of the preceding claims, **characterized in that** it comprises at least 5 upstream measurement devices (20 and/or 22) and/or at least 5 downstream measurement devices (24).

10. The apparatus according to any of the preceding claims, **characterized in that** it also comprises on or more of an injection gas source (10), a tracer source (12), an injection gas control valve (14), a tracer inflow control valve (16), a fluid analyser (17), an injection line (18), a tracer inlet (19), a production line output (26), communication points (28), a packer (30), perforation (32), a production casing (34), an intermediate casing (36), surface casing (38), conductor casing (40), an A-annulus (48), a B-annulus (46), a C-annulus (44), a D-annulus (42), a pressure sensor (50), a flow meter (52), a wellhead (54), cement (58), a hanger (60), an array of measurement devices (64), flow valves (70), a control unit (72) and/or wireless gas cards (74).

11. The apparatus according to any of the preceding claims, **characterized in that** that it also comprises at least two annuli (42, 44, 46 or 48) and a plurality of measurement devices (20, 22 and/or 24), where at least one measurement device per annulus is in communication with the respective annulus.

12. The apparatus according to any of the preceding claims, **characterized in that** at least one pressure sensor (50) and/or flow meter (52) per annulus (42, 44, 46 or 48) is in communication with the respective annulus.

13. The apparatus according to any of the preceding claims, **characterized in that** at least one measurement (20, 22 and/or 24) device capable of measuring the liquid level in an annulus (42, 44, 46 or 48) is in communication with this annulus.

14. A method for determining flow characteristics of produced fluid in a well during production operations using an apparatus according to any of the previous claims, comprising at least the following steps:

- a. collecting data from the measurement devices (20, 22 and/or 24),
- b. determine at least one flow parameter of the production fluid.

15. Using the apparatus according to any of the claims 1 to 13 to determine the leak rate between the injection line and at least one neighbouring line.

16. Using the apparatus according to any of the claims 1 to 13 to measure the flow rate of the production fluid in the production line.

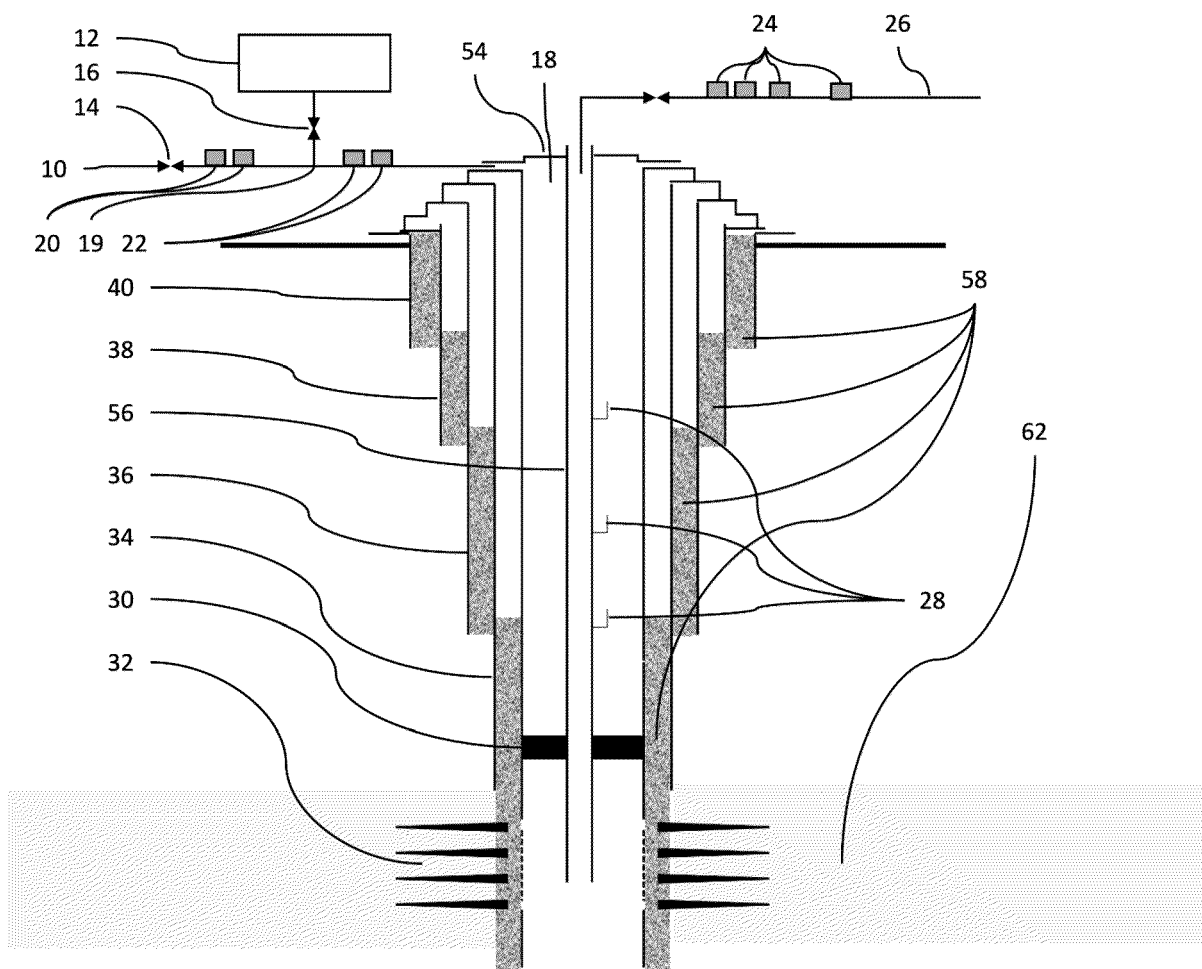


Fig. 1

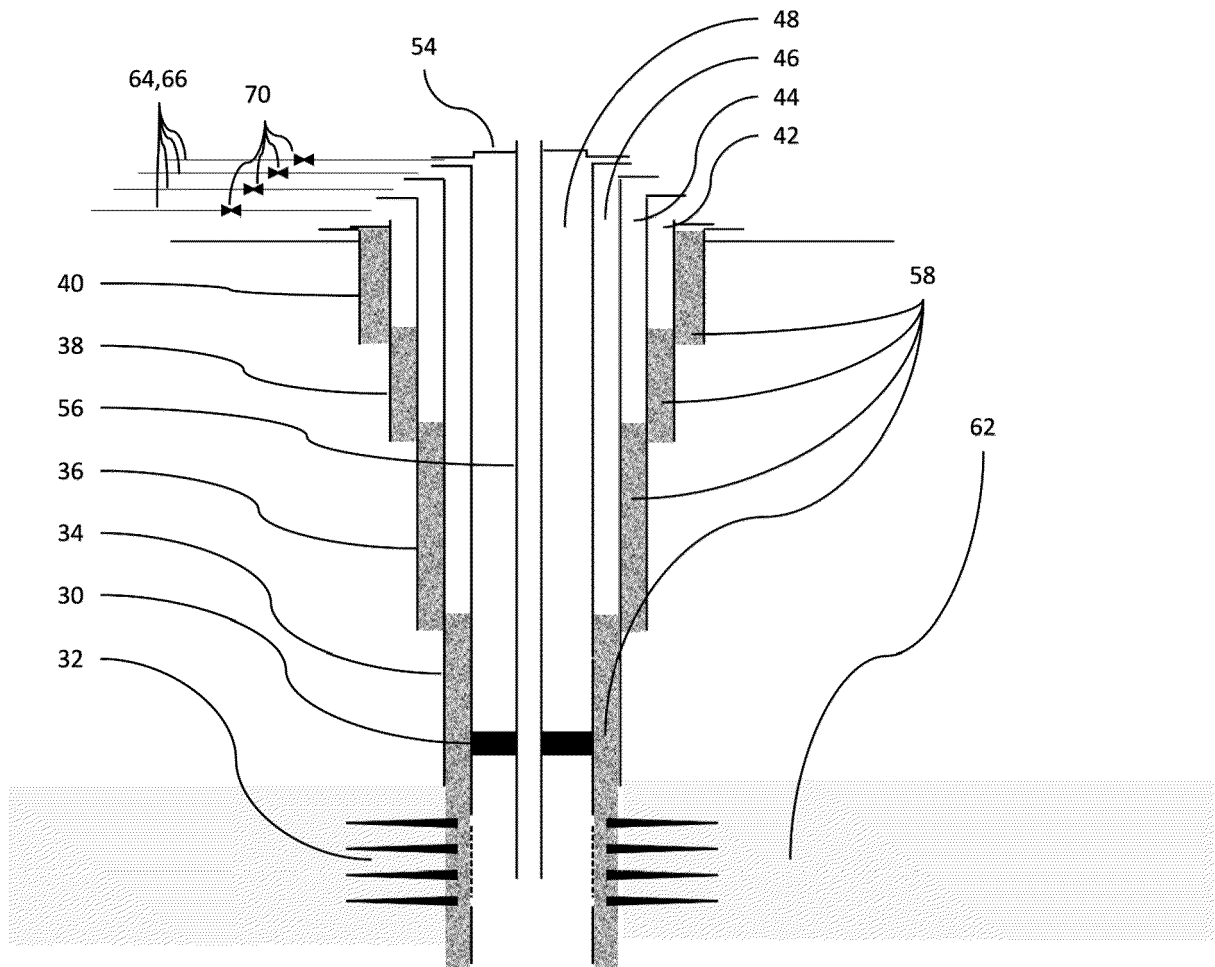


Fig. 2

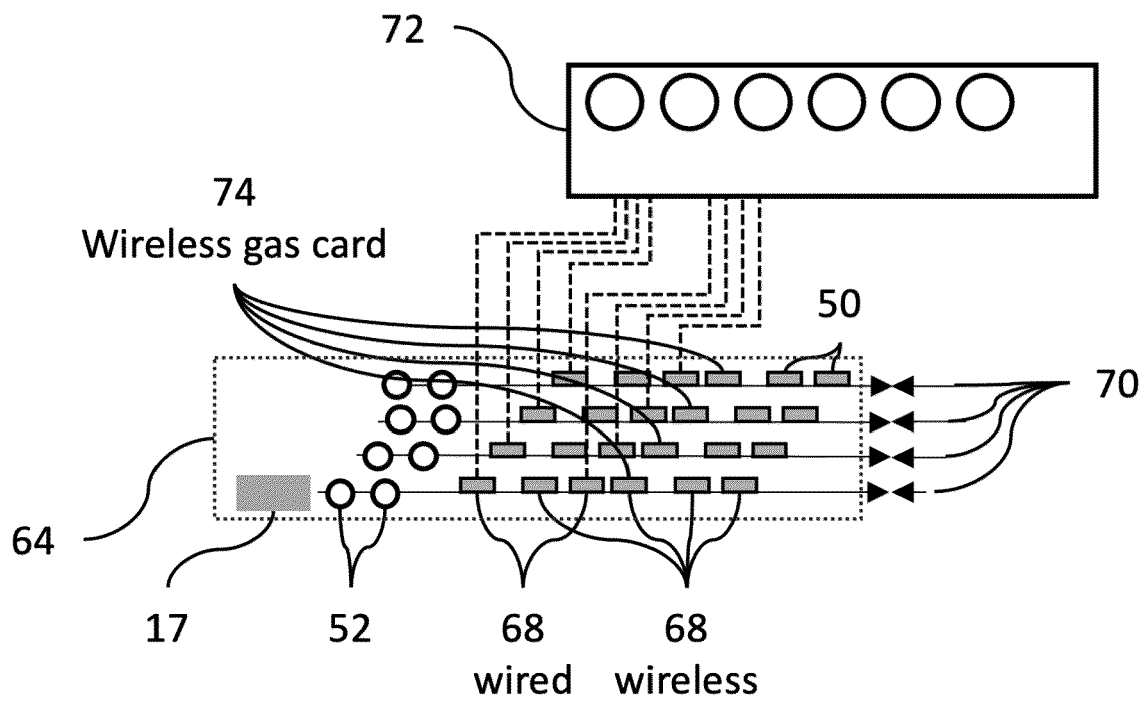


Fig. 3

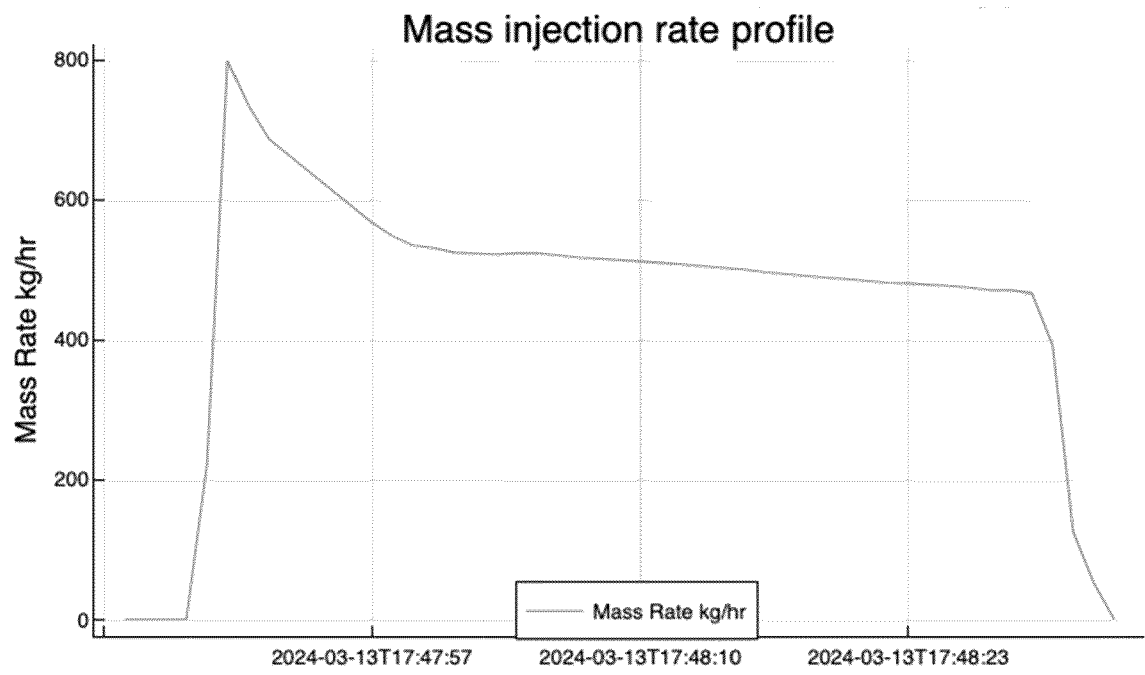


Fig. 4

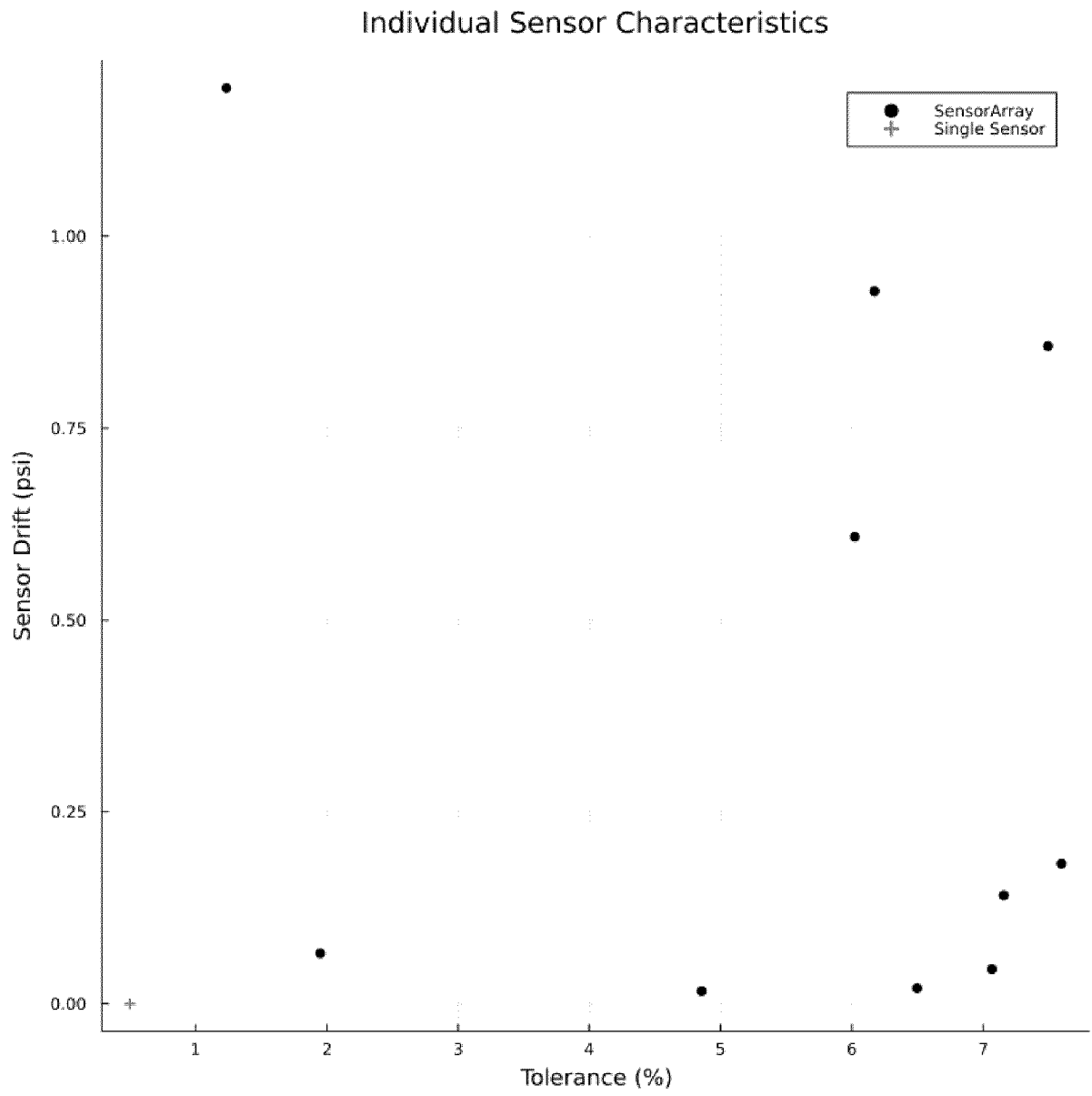


Fig. 5

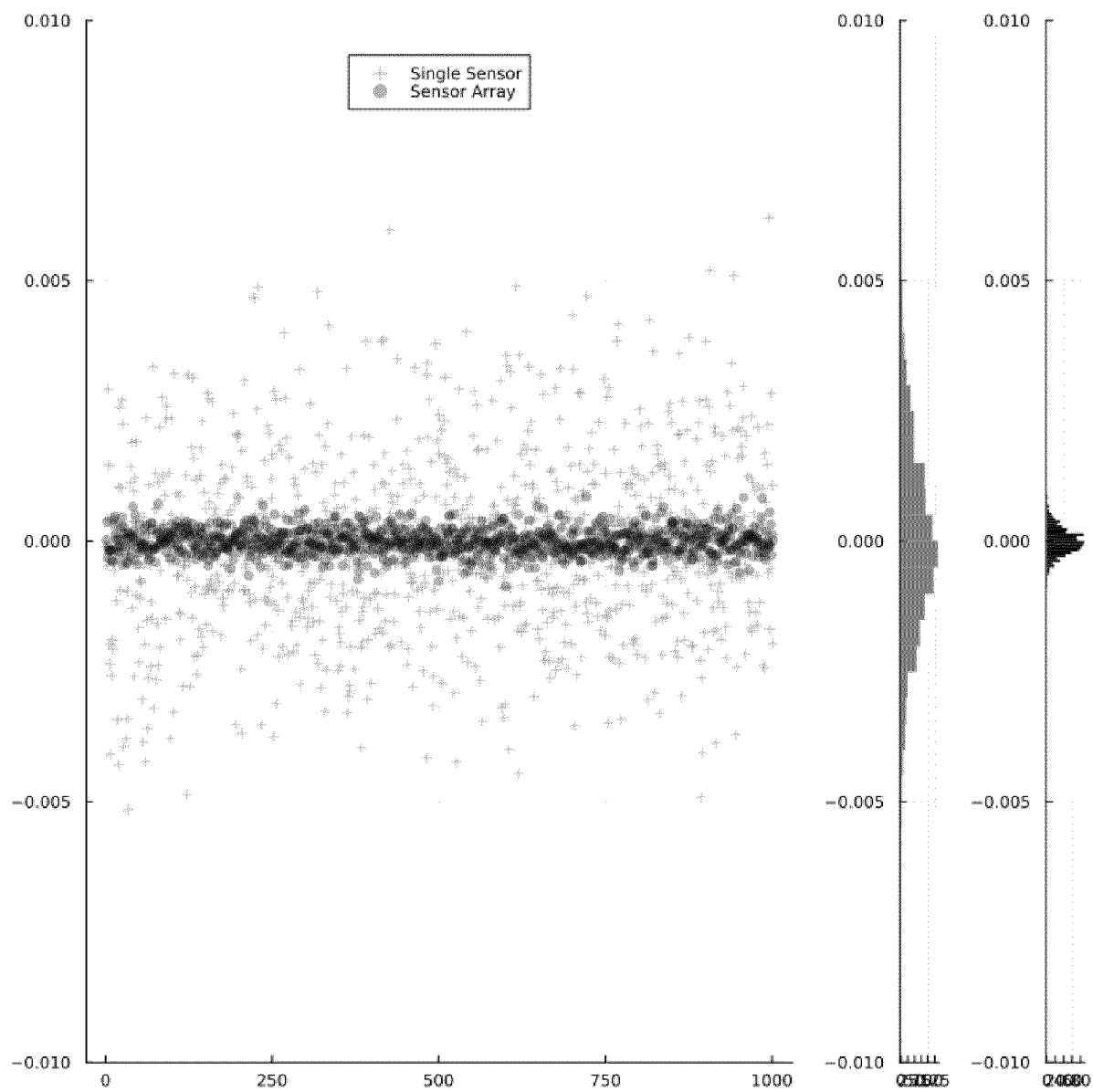


Fig. 6



EUROPEAN SEARCH REPORT

Application Number

EP 25 17 0727

DOCUMENTS CONSIDERED TO BE RELEVANT

Category	Citation of document with indication, where appropriate, of relevant passages	Relevant to claim	CLASSIFICATION OF THE APPLICATION (IPC)
X	WO 2024/211747 A2 (SCHLUMBERGER TECHNOLOGY CORP [US]; SCHLUMBERGER CA LTD [CA] ET AL.) 10 October 2024 (2024-10-10)	1-3,6,9, 10,12-16	INV. E21B47/10 E21B47/107
A	* paragraphs [0055] - [0059]; figures 4A-B *	4,5,7,8, 11	E21B47/11
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