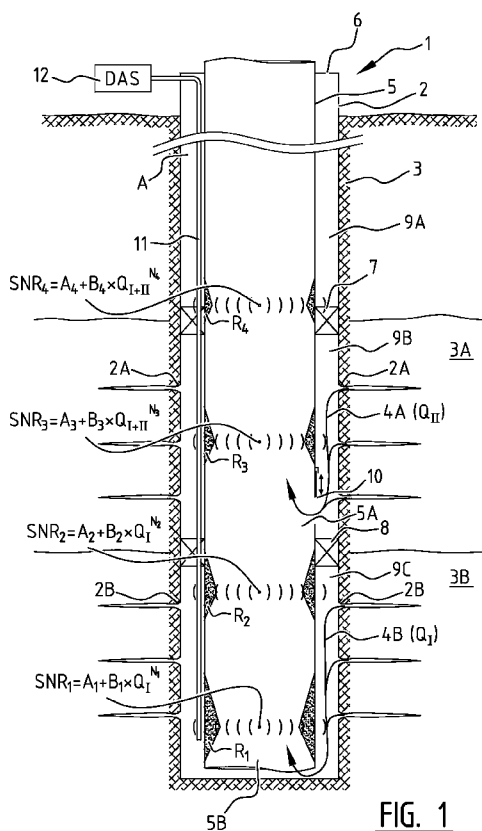




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- (71) Applicant (for US only): **SHELL OIL COMPANY** [US/US]; One Shell Plaza, P.O. Box 2463, Houston, Texas 77252-2463 (US).
- (71) Applicant (for all designated States except US): **SHELL INTERNATIONALE RESEARCH MAATSCHAPPIJ B.V.** [NL/NL]; Carel van Bylandtlaan 30, NL-2596 The Hague (NL).
- (72) Inventors: **IN'T PANHUIS, Petrus Hendrikus Maria Wilhemus**; Kessler Park 1, NL-2288GS Rijswijk (NL).
DEN BOER, Johannis Josephus; Kessler Park 1, NL-2288GS Rijswijk (NL).
- (72) Inventor: **KUSTERS, Roel Marie** (deceased).
- (72) Inventors: **ROY, Dayeeta**; Kessler Park 1, NL-2288GS Rijswijk (NL). **MUSTAFINA, Daria**; Kessler Park 1, NL-2288GS Rijswijk (NL).
- (74) Agents: **WIRZ, Melody E.** et al.; Shell Oil Company, One Shell Plaza, P.O. Box 2463, Houston, Texas 77252-2463 (US).
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[Continued on next page]

(54) Title: METHOD AND SYSTEM FOR MONITORING FLUID FLOW IN A CONDUIT



(57) Abstract: A method for monitoring fluid flow in a conduit (5) comprises: - acoustically coupling an optical fiber (11) to the conduit (5) adjacent one or more flow restrictions (R_1 - R_4) in the conduit; - inducing a Distributed Acoustic Sensing (DAS) assembly (12) to measure an acoustic noise signature (SNR_{1-4}) generated in the fiber (11) by the fluid flowing through each flow restriction (R_1 - R_4); - deriving the fluid flow rate of the fluid ($Q_{I, Q_{I+II}}$) flowing through each flow restriction (R_1 - R_4) from the measured acoustic noise signature (SNR_{1-4}); and - displaying the derived fluid flow rate ($Q_{I, Q_{I+II}}$) at a fluid flow rate monitoring display.



SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN,
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DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT,
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METHOD AND SYSTEM FOR MONITORING FLUID FLOW IN A CONDUIT

BACKGROUND OF THE INVENTION

The invention relates to a method and system for
5 monitoring fluid flow in a conduit.

A variety of flowmeters is currently available to monitor
fluid flow in a conduit. Many existing flowmeters are costly
pieces of equipment that are difficult to install in a confined
space, such as downhole in an oil and/or gas production or in a
10 fluid injection well.

It is known from US Patent No.6378380 to monitor in such
case fluid flow by measuring a pressure difference across a
flow restriction in the conduit. However, the installation and
calibration of such a flowmeter in an oil and/or gas production
15 or in a fluid injection well is still a complex and costly
operation.

A further disadvantage of existing in-well venturi
flowmeters is that delta-P (Δp) sensors are not available for
downhole use and that therefore absolute pressure gauges to be
20 installed upstream and downstream of each venturi meter. The
consequence is that to derive at a downhole delta-P (Δp)
measurement two large numbers have be subtracted which is a
large source of inaccuracy.

To reduce this inaccuracy, usually a downhole venturi is
25 usually designed with a large beta (i.e. a small inner
diameter) to increase the pressure drop (Δp). The large
pressure drop ($\Delta p > 1$ bar) inhibits the fluid flux and the small
inner diameter of the venturi may prevent logging tools to pass
the venturi. To permit use of a venturi with a relatively large
30 inner diameter to measure a relatively small delta-P, which
requires selection of highly sensitive pressure gauges (like
quartzdyne gauges), which are very expensive. Furthermore, each
pressure gauge has a defined operating range (often 1:10)

resulting in a relatively small operating range of the venturi flow meter (1:3). The selection of pressure gauges for downhole use therefore requires a good understanding of possible variations of the expected downhole pressures and pressure drops (Δp) throughout the life time of the well.

There is a need to avoid or alleviate the limitations associated with the conventional Δp measuring method.

Furthermore there is a need for a method and system for monitoring fluid flow at multiple points in a conduit in a cost effective manner, without the need to install pressure gauges and other associated costly equipment.

SUMMARY OF THE INVENTION

In accordance with the invention there is provided a method for monitoring fluid flow in a conduit, the method comprising:

- acoustically coupling an optical fiber to the conduit adjacent to a flow restriction in the conduit;
- inducing a Distributed Acoustic Sensing (DAS) assembly to measure an acoustic noise signature generated in the optical fiber by the fluid flowing through the flow restriction;
- deriving the fluid flow rate of the fluid flowing through the flow restriction from the measured acoustic noise signature; and
- displaying the derived fluid flow rate at a fluid flow rate monitoring display.

The fluid flow rate Q may be derived from the measured acoustic noise signature SNR following empirical correlations of McKinley et.al., which require a multi-rate test to determine a number of calibration parameters that depend on the number of flow restrictions.

The empirical correlations of McKinley et.al. optionally comprise the formula:

$$\text{SNR} = A + B \cdot Q^N$$

, wherein A, B and N are the empirically determined calibration parameters, which may be determined by a flow test using a multi-rate production test wherein the gas and liquid production is measured at surface by means of a test separator or multiphase flowmeter, or wherein a production logging tool is inserted in the conduit in the vicinity of the flow restriction and the fluid flow rate Q through the flow restriction is varied and measured by the production logging tool while the acoustic noise signature SNR is measured by the optical fiber and DAS interrogator assembly.

In a multiphase fluid mixture, such as a two-phase flow, the fluid flow rates of the individual phases may be derived from the acoustic noise signatures (SNR) measured across two consecutive flow restrictions with different flow resistivities, such as flow venturi's with different Outer/Inner Diameter (OD/ID) ratios (Beta's). From two known multiphase flow equations, two individual flow parameters may be derived, such as gas and liquid flowrates in gas/liquid mixtures, and water and oil flowrates in oil/water mixtures.

The optical fiber and DAS assembly may be induced to measure the acoustic noise signature SNR of acoustic signals within different frequency bands ranging from 1-10, 10-200, 200-2000 or 2000-5000 Hz transmitted by the fluid flow through the flow restriction to the optical fiber.

In accordance with the invention there is furthermore provided a system for monitoring fluid flow in a conduit, the system comprising:

- an optical fiber which is acoustically coupled to an outer surface of the conduit adjacent to a flow restriction in the conduit;
- a Distributed Acoustic Sensing (DAS) assembly which is configured to measure an acoustic noise signature generated in

the fiber by the fluid flowing through the flow restriction;
and

- a fluid flow monitoring display for displaying the fluid flow rate of the fluid flowing through the flow restriction derived
5 from the measured acoustic noise signature.

The system may further comprise a computer readable medium, which when connected to a computer, causes the computer to derive the fluid flow rate Q from the measured acoustic noise signature SNR following empirical correlations of
10 McKinley et.al., which correlate a number of calibration parameters that depend on the number of flow restrictions.

The empirical correlations of McKinley et.al. may comprise using the formula:

$$\text{SNR} = A + B \cdot Q^N$$

15 , wherein A , B and N are the empirically determined calibration parameters.

The conduit may be a hydrocarbon fluid transportation conduit arranged within or connected to a hydrocarbon fluid production well or a fluid injection conduit connected to or
20 arranged in a fluid injection well through which fluid is injected into a hydrocarbon fluid containing formation.

A plurality of flow restrictions with different flow resistivities may be arranged along at least part of the length of the conduit and the flow restrictions may be arranged in a
25 production tubing downstream of a production zone or in a fluid injection tubing upstream of an injection zone of a well to measure the amount of fluid produced from or injected into the formation in that zone.

These and other features, embodiments and advantages of
30 the method and system according to the invention are described in the accompanying claims, abstract and the following detailed description of non-limiting embodiments depicted in the accompanying drawings, in which description reference numerals

are used which refer to corresponding reference numerals that are depicted in the drawings.

Similar reference numerals in different figures denote the same or similar objects.

5

BRIEF DESCRIPTION OF THE DRAWINGS

Figure 1 is a schematic longitudinal sectional view of a inflow region of a well in which fluid flow is monitored using the method and system according to the invention;

10 Figure 2 is a schematic side and partial longitudinal sectional view of a well in which pressure drop and fluid influx is monitored using the conventional ΔP method and the method according to the invention; and

15 Figure 3 shows a comparison of the pressure drop measured in the well shown in Figure 2 using the conventional ΔP method and the method according to the invention.

DETAILED DESCRIPTION OF THE DEPICTED EMBODIMENTS

20 Figure 1 is a schematic longitudinal sectional view of an oil and/or gas production well 1.

The well 1 comprises a well casing 2 which is cemented within a surrounding subsurface earth formation 3. The formation 3 comprises two oil and/or gas bearing layers 3A and 3B and the well casing 2 is perforated by an upper assembly of
25 perforations 2A and a lower assembly of perforations 2B to facilitate influx of crude oil and/or natural gas from these layers 3A and 3B into the interior of the well 1, as illustrated by arrows 4A and 4B.

30 A production tubing 5 is suspended from a wellhead 6 into the well 1 and is sealingly connected to the well casing 2 by a pair of packers 7 and 8 that are located adjacent to the upper rims of the oil and/or gas bearing formation layers 3A and 3B, so that an annular space 9 between the production tubing 5 and

well casing 2 is divided into an upper annular space 9A, an intermediate annular space 9B and a lower annular space 9C.

Crude oil and/or natural gas is permitted to flow from the lower crude oil and/or natural gas bearing formation layer 3B via the lower assembly of perforations 2B, the lower annular space 9C and the open lower end of the production tubing 5 into a lower section 5B of the interior of the production tubing 5, as illustrated by arrow 4B.

Crude oil and/or natural gas is permitted to flow from the upper crude oil and/or natural gas bearing formation layers 3A via the upper assembly of perforations 2A, the intermediate annular space 9B and a sliding sleeve valve 10 into an upper section 5A of the interior of the production tubing 5.

A pair of lower venturi flow restrictions R1 and R2 is arranged in the lower section 5B of the interior of the production tubing 5 below the sliding sleeve valve 10 and a pair of upper venturi flow restrictions R3 and R4 is arranged in the upper section 5A of the interior of the production tubing 5 above the sliding sleeve valve 10.

Figure 2 shows an oil and/or gas production well 20 with two inflow zones 20A and 20B into which crude oil and/or natural gas flows through perforated sections 21A-B of a well casing 21 into the well interior in which a production tubing 22 is suspended from a wellhead 24, whilst the lower region of the well interior is separated by packers 23 A and B into the two well inflow zones 20 A & B.

In each well inflow zone 20 A and 20B the production tubing 22 comprises a perforated section 22A, 22B which is connected to an annulus 22C, 22D surrounding the interior of the production tubing 22 that contains an annular Inflow Control Valve(ICV) 26A, 26B. Each annular ICV 26A, 26B forms a flow restriction for the flux of well effluents Q1, Q2 passing through the annuli 22C,22D into other parts of the interior of

the production tubing 22.

The fluid passing through each ICV 26A, 26B generates noise (SNR_1 and SNR_2) that is monitored by acoustically coupling an optical fiber 27 to each ICV 26A, 26B. The fiber 27 is connected to a Distributed Acoustic Sensing (DAS) assembly 28, which transmits light pulses through the optical fiber 27 and measures strain variations along the length of the fiber 27 generated by the noise SNR_1 and SNR_2 (Decibel) on the basis of time-of flight and Raleigh wavelength variations of backscattered light pulses. Subsequently the fluid flow rate Q (M^3/S) passing through the interior of each ICV 26A, 26B is derived from the measured acoustic noise signature SNR following empirical correlations of McKinley et.al., which require a multi-rate test to determine a number of calibration parameters that depend on the number of flow restrictions. The empirically determined calibration parameters may be determined by a multi-rate production test wherein the gas and liquid production is measured at surface by means of a test separator or multiphase flowmeter.

In the embodiment shown in Figure 2 the empirical correlations of McKinley et.al. comprise the formula:

$$SNR_i = A_i + B_i \cdot Q_i^{N_i}$$

, wherein A_i , B_i and N_i are empirically determined calibration parameters, which may be determined for each ICV 26A and 26B by inserting a Production Logging Tool (PLT) into the tubing 22 to monitor the flow rates Q_1 and Q_2 and then stepwise varying each of the flowrates Q_1 and Q_2 whilst simultaneously monitoring variations of the acoustic noise rates SNR_1 and SNR_2 adjacent to each of the ICVs 26A and 26B by means of the optical fiber 28 and DAS assembly 27.

Accordingly the acoustic noise SNR_1 measured at the lower Inflow Control Valve ICV 26A is $SNR_1 = A_1 + B_1 \cdot Q_1^{N_1}$, wherein A_1 , B_1 and N_1 are empirically determined calibration

parameters and the acoustic noise SNR_2 measured at the upper Inflow Control Valve ICV 26B is $SNR_2 = A_2 + B_2 \cdot Q_2^{N_2}$, wherein A_2 , B_2 and N_2 are empirically determined calibration parameters.

In the embodiment shown in Figure 2, two pairs of pressure gauges P1&P2 and P3&P4 are arranged in the production tubing 22 to measure the pressure drop across each ICV 26A-26B (i.e. the difference between the annular and tubing pressure) to determine the fluid inflow rate Q through each ICV 26A-26B in parallel to the fluid flow rate measurement using the fiber optical cable 27 and DAS assembly according to the invention.

Figure 3 shows results of comparisons of fluid flow rate measurements using the conventional pressure drop (ΔP) method and the acoustic noise measuring method (DAS) according to the invention.

The graphs show comparisons of Δp measurements using the conventional Δp method, wherein the pressure drop across each ICV 26A, 26B is measured using the pressure gauges P1&P2 and P3&P4 and the acoustic noise (SNR) measurement according to the invention, wherein the acoustic noise SNR at or near each ICV 26A, 26B is measured, which comparisons indicate that there is an accurate match of the flow measurements using acoustic noise (SNR) method according to the invention with those using the conventional Δp measuring method.

The conventional Δp measuring method is commonly used to measure fluid flow rates Q passing through flow restrictions, such as Orifices, Venturi's and Inflow Control Valves on the basis of well-known pressure flow rate relationships, such as Bernouilli's law.

A disadvantage of the use of conventional pressure gauges P1-P4 is that they are expensive pieces of equipment that have a limited operating range (1:10), and that are difficult to install, calibrate and inspect at remote locations, such as

downhole in oil and/or gas production wells or in water, steam and/or other fluid injection wells.

In the method and system according to the invention only an optical fiber 27 is installed downhole in the well, so that
5 the Δp and associated fluid flow measurements can be performed in a more cost effective manner than with the conventional Δp method.

Further advantages of the method and system according to the invention are that DAS is extremely sensitive in picking up
10 thermal and acoustic noise, allowing a small beta (large inner diameter of the venturi and low pressure drop) offering no objection for well intervention tools like Production Logging Tools. Secondly, the DAS measurement is a direct and single measurement from which the flowrate can be derived. Thirdly,
15 the dynamic range of DAS is very large, large enough to cover the full range of ΔP 's. Fourthly, only a single optical fibre is required on which (an almost unlimited number of) venturi-meters can be multi-dropped. Fifthly, the combination of two venturi's in series and associated sensitive DAS
20 assemblies may reveal information about gross and WC (watercut) and or the GVF (Gas-Volume-Fraction) in a multiphase flow in downhole well tubings and/or other multiphase fluid transportation tubulars.

C L A I M S

1. A method for monitoring fluid flow in a conduit, the method comprising:
- 5 - acoustically coupling an optical fiber to the conduit adjacent to a flow restriction in the conduit;
- inducing a Distributed Acoustic Sensing (DAS) assembly to measure an acoustic noise signature generated in the optical fiber by the fluid flowing through the flow
- 10 restriction;
- deriving the fluid flow rate of the fluid flowing through the flow restriction from the measured acoustic noise signature; and
- displaying the derived fluid flow rate at a fluid flow
- 15 rate monitoring display.
2. The method of claim 1, wherein the fluid flow rate Q is derived from the measured acoustic noise signature SNR following empirical correlations of McKinley, which correlate a number of empirical calibration parameters
- 20 that depend on the number of flow restrictions.
3. The method of claim 2, wherein the empirical correlations of McKinley comprise the formula:
- $SNR = A + B \cdot Q^N$
- , wherein A , B and N are empirically determined
- 25 calibration parameters.
4. The method of claim 2 or 3, wherein the empirically determined calibration parameters A , B and N and other empirical calibration parameters are determined by a multi-rate production test wherein the gas and liquid
- 30 production is measured at surface by means of a test separator or multiphase flowmeter, or by a flow test wherein a production logging tool is inserted in the conduit in the vicinity of the flow restriction and the

fluid flow rate Q through the flow restriction is varied and measured by the production logging tool while the acoustic noise signature SNR is measured by the optical fiber and DAS interrogator assembly.

- 5 5. The method of claim 2, 3, or 4, wherein the optical cable and DAS assembly is induced to measure the acoustic noise signature SNR of acoustic signals in different frequency bands of 1-10, 10-200, 200-2000 and 2000-5000 Hz transmitted by the fluid flow through the flow restriction
- 10 to the optical fiber.
6. The method of claim 1, wherein the conduit is a hydrocarbon fluid transportation conduit arranged within or connected to a hydrocarbon fluid production well or a fluid injection conduit connected to or arranged in a
- 15 fluid injection well through which fluid is injected into a hydrocarbon fluid containing formation.
7. The method of claim 6, wherein the conduit is arranged downhole in the hydrocarbon fluid production well or in the fluid injection well.
- 20 8. The method of claim 7, wherein a plurality of artificial flow restrictions, such as venturi-inserts, are arranged along at least part of the length the conduit.
9. The method of claim 8, wherein the flow restrictions have different flow resistivities.
- 25 10. The method of claim 8 or 9, wherein the flow restrictions are arranged downstream of a production zone or upstream of an injection zone of the well and the method is used to measure the amount of fluid produced from or injected into the formation in that zone.
- 30 11. system for monitoring fluid flow in a conduit, the system comprising:
- an optical fiber which is acoustically coupled to an outer surface of the conduit adjacent to a flow

restriction in the conduit;

- a Distributed Acoustic Sensing (DAS) assembly which is configured to measure an acoustic noise signature generated in the fiber by the fluid flowing through the flow restriction; and
- a fluid flow monitoring display for displaying the fluid flow rate of the fluid flowing through the flow restriction derived from the measured acoustic noise signature.

12. The system of claim 11, wherein the system further comprises a computer readable medium, which when connected to a computer, causes the computer to derive the fluid flow rate Q from the measured acoustic noise signature SNR using the formula:

$$\text{SNR} = A + B \cdot Q^N$$

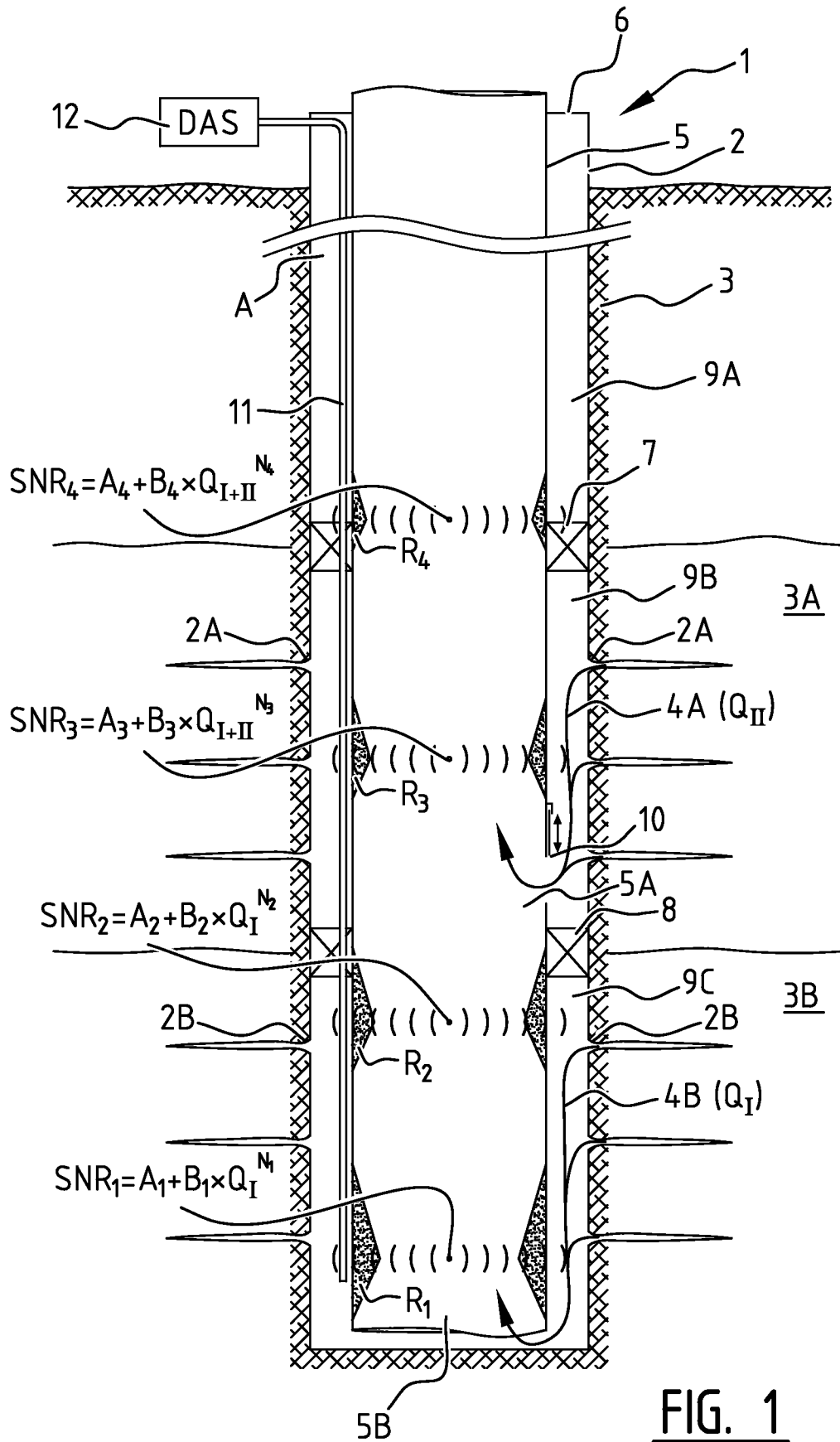
, wherein A, B and N are empirically determined calibration parameters.

13. The system of claim 11 or 12, wherein the conduit is a hydrocarbon fluid transportation conduit arranged within or connected to a hydrocarbon fluid production well or a fluid injection conduit connected to or arranged in a fluid injection well through which fluid is injected into a hydrocarbon fluid containing formation.

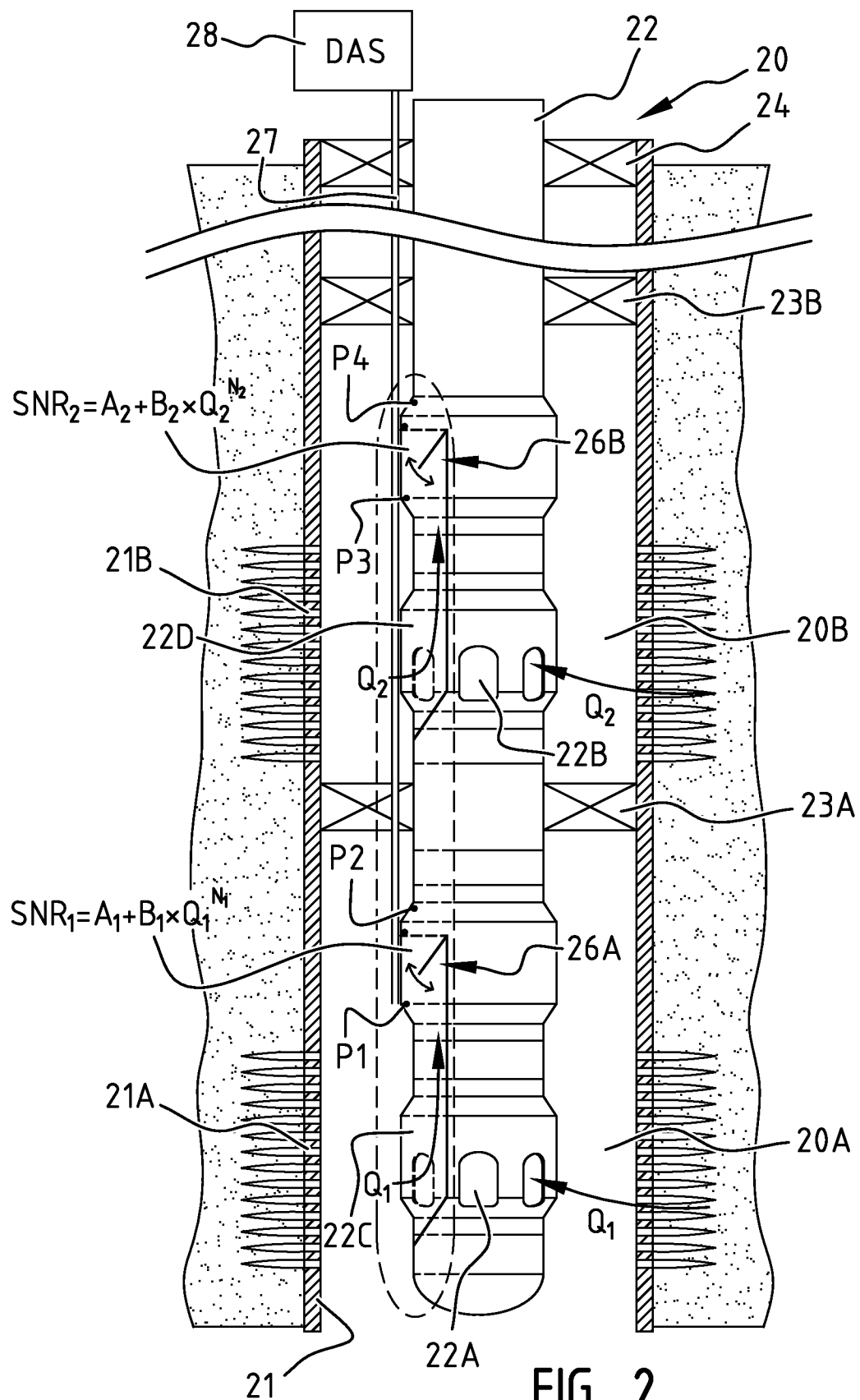
14. The method of claim 13, wherein the conduit is a well tubing arranged downhole in the hydrocarbon fluid production well or in the fluid injection well.

15. The system of claim 14, wherein at least two flow restrictions with different flow resistivities are arranged in the well tubing downstream of each production zone or upstream of each injection zone of the well and the system is configured to measure the amount of fluid produced from or injected into the formation in that zone.

1/3



2/3

**FIG. 2**

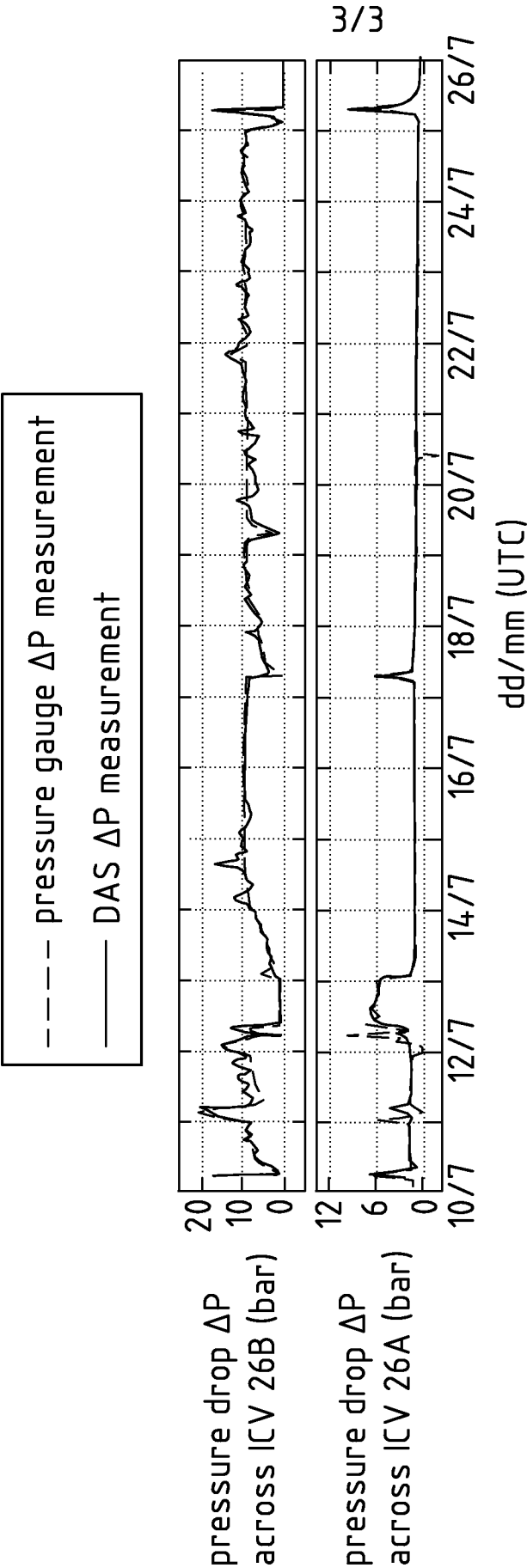


FIG. 3

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2014/062324**A. CLASSIFICATION OF SUBJECT MATTER****E21B 43/12(2006.01)i, E21B 21/08(2006.01)i**

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B 43/12; E21B 47/10; G06F 19/00; G01V 9/02; E21B 43/00; G01F 1/20; E21B 41/00; G01F 1/42; E21B 21/08

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

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

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

eKOMPASS(KIPO internal) & Keywords:wellbore, Distributed Acoustic Sensing (DAS) assembly, optical fiber, acoustic noise signature, fluid flow rate, SNR, flow restriction, computer readable medium, empirical calibration parameter, multi-rate production test and venturi-insert

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2012-0277995 A1 (HARTOG et al.) 01 November 2012	1,6-11,13-15
A	See abstract; paragraphs [0002]-[0069]; claims 1,14,24; and figure 1B.	2-4,12
Y	US 2011-0214498 A1 (REZGUI et al.) 08 September 2011	1,6-11,13-15
A	See abstract; paragraphs [0012],[0032],[0055]; and claim 1.	
A	US 2009-0037113 A1 (AKRAM et al.) 05 February 2009	1-4,6-15
A	See abstract; paragraphs [0010]-[0043]; claims 1,11; and figures 5,6.	
A	US 2003-0121335 A1 (LUI et al.) 03 July 2003	1-4,6-15
A	See abstract; paragraphs [0010]-[0011]; and figures 2,5.	
A	US 2009-0294123 A1 (MESCALL et al.) 03 December 2009	1-4,6-15
A	See abstract; paragraphs [0006]-[0010]; and claims 9-14.	



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents:

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

"E" earlier application or patent but published on or after the international filing date

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"O" document referring to an oral disclosure, use, exhibition or other means

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

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

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

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

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Date of mailing of the international search report

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Name and mailing address of the ISA/KR

International Application Division
Korean Intellectual Property Office
189 Cheongsu-ro, Seo-gu, Daejeon Metropolitan City, 302-701,
Republic of Korea

Facsimile No. ++82 42 472 3473

Authorized officer

HWANG, Chan Yoon

Telephone No. +82-42-481-3347



INTERNATIONAL SEARCH REPORTInternational application No.
PCT/US2014/062324**Box No. II Observations where certain claims were found unsearchable (Continuation of item 2 of first sheet)**

This international search report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:
2. ☐ Claims Nos.:
because they relate to parts of the international application that do not comply with the prescribed requirements to such an extent that no meaningful international search can be carried out, specifically:
3. ☒ Claims Nos.: 5
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box No. III Observations where unity of invention is lacking (Continuation of item 3 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

1. ☐ As all required additional search fees were timely paid by the applicant, this international search report covers all searchable claims.
2. ☐ As all searchable claims could be searched without effort justifying an additional fees, this Authority did not invite payment of any additional fees.
3. ☐ As only some of the required additional search fees were timely paid by the applicant, this international search report covers only those claims for which fees were paid, specifically claims Nos.:
4. ☐ No required additional search fees were timely paid by the applicant. Consequently, this international search report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

Remark on Protest

- ☐ The additional search fees were accompanied by the applicant's protest and, where applicable, the payment of a protest fee.
- ☐ The additional search fees were accompanied by the applicant's protest but the applicable protest fee was not paid within the time limit specified in the invitation.
- ☐ No protest accompanied the payment of additional search fees.

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2014/062324

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