(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
29 November 2018 (29.11.2018)

(10) International Publication Number
WO 2018/215763 A1

(51) International Patent Classification:
E21B 49/00 (2006.01) *E21B 47/06* (2012.01)

(21) International Application Number:
PCT/GB2018/051394

(22) International Filing Date:
23 May 2018 (23.05.2018)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
1708290.0 24 May 2017 (24.05.2017) GB

(71) Applicant: GEOMEC ENGINEERING LIMITED [GB/GB]; c/o Hill Dickinson LLP, The Broadgate Tower (6th Floor), 20 Primrose Street, London EC2A 2EW (GB).

(72) Inventor: SANTARELLI, Frederic Joseph; c/o Geomec Engineering AS, Postbox 8034, Ipark, 4068 Stavanger (NO).

(74) Agent: IPENTUS LIMITED; The Old Manse, Wilsontown, By Forth, Lanark, Strathclyde ML11 8EP (GB).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JO, JP, KE, KG, KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

(54) **Title:** IMPROVEMENTS IN OR RELATING TO INJECTION WELLS

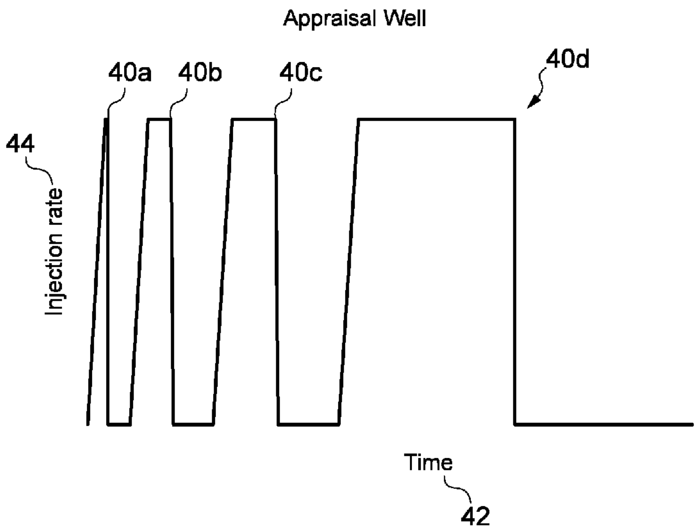


Fig. 2

(57) **Abstract:** A method for providing a well injection program in which injection testing is performed on an appraisal well. An appraisal well is selected, downhole sensors are located in the well to measure pressure and temperature, water is injected into the well in a series of step rate tests or injection cycles, the data is modelled to determine a thermal stress characteristic of the well and by reservoir modelling the optimum injection parameters are determined for the well injection program to provide for maximum recovery. This overcomes the need for making thermal stress characteristic measurements on core samples.

WO 2018/215763 A1

[Continued on next page]

Published:

— *with international search report (Art. 21(3))*

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

IMPROVEMENTS IN OR RELATING TO INJECTION WELLS

The present invention relates to injecting fluids into wells and more particularly, to a method for injection testing in appraisal wells to evaluate thermal stress effect characteristics for reservoir modelling and so better determine injection parameters for the well.

Current hydrocarbon production is primarily focussed on maximising the recovery factor from a well. This is because we have already exploited all the areas which might contain oil leaving only those that are in remote and environmentally sensitive areas of the world (e.g. the Arctic and the Antarctic). While there are huge volumes of unconventional hydrocarbons, such as the very viscous oils, oil shales, shale gas and gas hydrates, many of the technologies for exploiting these resources are either very energy intensive (e.g. steam injection into heavy oil), or politically/environmentally sensitive (e.g. 'fraccing' to recover shale gas).

To improve the recovery factor in a well it is now common to inject fluids, typically water, into the reservoir through injection wells. This form of improved oil recovery uses injected water to increase depleted pressure within the reservoir and also move the oil in place so that it may be recovered. If produced water is re-injected this also provides environmental benefits.

Reservoir models are used in the industry to analyze, optimize, and forecast production. Such models are used to investigate injection scenarios for maximum recovery and provide the injection parameters for an injection program. Geological, geophysical, petrophysical, well log, core, and fluid data are typically used to construct the reservoir models. The properties of the rock in the formation are traditionally obtained by taking measurements on core samples and the results are used in the models.

A known disadvantage in this approach is in the limitation of the models used and their reliance on the data provided by the core samples. While many techniques exist to contain and transport the core samples so that they represent well conditions in the laboratory, many measurements cannot scale from the laboratory to the well and there is a lack of adequate up-scaling methodologies.

Additionally, on injecting a cool fluid into warm subterranean reservoir, a cooling effect will occur around the injector. This alters the stresses in the region with altered temperature. A consequence is that the fracture pressure around an injector will vary with time. The amount of variation will be dependent on the thermal stress characteristics of the formation. While these can theoretically be measured on a core sample in the laboratory such a measurement which is dependent on a pressure/temperature relationship can’t be adequately scaled and they are found to be multiple factors out when attempts are made to scale to well dimensions.

US 8,116,980 to ENI S.p.A. describes a testing process for testing zero emission hydrocarbon wells in order to obtain general information on a reservoir, comprising the following steps: injecting into the reservoir a suitable liquid or gaseous fluid, compatible with the hydrocarbons of the reservoir and with the formation rock, at a constant flow-rate or with constant flow rate steps, and substantially measuring, in continuous, the flow-rate and injection pressure at the well bottom; closing the well and measuring the pressure, during the fall-off period (pressure fall-off) and possibly the temperature; interpreting the fall-off data measured in order to evaluate the average static pressure of the fluids (Pav) and the reservoir properties: actual permeability (k), transmissivity (kh), areal heterogeneity or permeability barriers and real Skin factor (S); calculating the well productivity. Such injection testing at an appraisal well has advantages over conventional production testing in removing the requirement to dispose of produced hydrocarbons with its incumbent safety and environmental issues. However, such testing has so far been limited to the determination of fluid properties, in particular the permeability, and formation damage in measuring the skin factor, to determine well productivity.

It is therefore an object of the present invention to provide a method for a well injection program in which injection testing is used to determine thermal stress characteristics of the well.

It is a further object of the present invention to provide a method for a well injection program in which injection testing is used to determine parameters for well interpretation.

According to a first aspect of the present invention there is provided a method for a well injection program, comprising the steps:

(a) selecting an appraisal well;
(b) selecting a perforation interval and length;
(c) locating at least one downhole sensor to measure pressure in the well;
(d) injecting a fluid into the well;
(e) varying the flow rate of injected fluid;
(f) measuring the pressure with flow rate variations to provide measured data;
(g) fitting a first model to the measured data to estimate a thermal stress characteristic of the well;
(h) inputting the thermal stress characteristic into a second model; and

(i) determining injection parameters from the second model.

In this way, by estimating the thermal stress characteristics before developing the field, injection parameters can be determined for injection confinement with the greatest injection efficiency.

Additionally, by determining the thermal stress characteristics at the well, more accurate calibration data is used in the second models than would be available from measurements on core samples.

Preferably, the method includes the steps of performing a series of step rate tests and measuring fracture pressure. In this way, fracturing can occur on the first step and other steps. Alternatively, the method includes the steps of performing injection cycling and fall-off analysis.

Preferably, the first model describes the development of the thermal stresses around the well on the measured data to estimate a thermal stress characteristic. More preferably the thermal stress characteristic is a thermal stress parameter.

Preferably the second model is a reservoir model or a hydraulic model. Such models are known in the art for well planning and optimization. In this way, the present invention can utilize models and techniques already used in industry.

Preferably, at least one downhole sensor also measures temperature. Preferably, the sensors data sampling rate is 1 Hz or greater. There may be a plurality of sensors to ensure redundancy.

Preferably the downhole sensors transmit data to the surface in real-time. Alternatively, the downhole sensors include memory gauges on which the measured data is stored.

Preferably the method includes the step of measuring pressure for different temperatures of injected fluid. In this way, better characterisation of the effects of the cooling effect can be determined.

Preferably the method includes the step of measuring pressure at different zones in the well. In this way, characterisation of fracture pressure and the thermal stresses can be determined over the formation.

Preferably, pressure, temperature and flow rate are measured at the surface of the well. In this way, the injection parameters based on these values can be better determined.

Preferably, the method includes the step of measuring the pressure and flow rate during the first injection cycle and shut in/step rate test and determining fracturing has occurred. In this way, remedial steps can be taken to ensure fracturing occurs in the second injection cycle and shut in. Preferably, parameters for the second injection cycle are determined from the first injection cycle. In this way, rate ramping schedule and duration of high rate injection can be optimized. Preferably, these steps are repeated for further injection cycles/step rate tests.

Preferably, the injected fluid is water. The injected fluid may be selected from a group comprising: drill water, filtered seawater or unfiltered seawater. The injected fluid may be treated such as with a bactericide or scale inhibitor. The injected fluid may further include a viscosifier. The method may include the step of introducing a viscosifier to the fluid during injection. In this way, the viscosifier can be added if fracturing is not achieved on a first injection cycle.

Preferably, the appraisal well has a well completion. More preferably the well completion is with a cemented and perforated liner over an interval. Other completions may be used such as open-hole screens with packers.

Preferably, the downhole sensors are run in the well on a string. The string may be drill pipe, test string or wireline.

Preferably the well injection parameters are selected from a group comprising: perforation length, injection fluid temperature, fluid pump rate, fluid pump duration and fluid injection volume.

Preferably, the method includes the further step of carrying out well injection using the well injection parameters.

Accordingly, the drawings and description are to be regarded as illustrative in nature and not as restrictive. Furthermore, the terminology and phraseology used herein is solely used for descriptive purposes and should not be construed as limiting in scope languages such as including, comprising, having, containing or involving and variations thereof is intended to be broad and encompass the subject matter listed thereafter, equivalents and additional subject matter not recited and is not intended to exclude other additives, components, integers or steps. Likewise, the term comprising, is considered synonymous with the terms including or containing for applicable legal purposes. Any discussion of documents, acts, materials, devices, articles and the like is included in the specification solely for the purpose of providing a context for the present invention. It is not suggested or represented that any or all of these matters form part of the prior art based on a common general knowledge in the field relevant to the present invention. All numerical values in the disclosure are understood as being modified by "about". All singular forms of elements or any other components described herein are understood to include plural forms thereof and vice versa.

While the specification will refer to up and down along with uppermost and lowermost, these are to be understood as relative terms in relation to a wellbore and that the inclination of the wellbore, although shown vertically in some Figures, may be inclined or even horizontal.

Embodiments of the present invention will now be described, by way of example only, with reference to the accompanying Figures, of which:

Figure 1 is a schematic illustration of an injection well test being performed on an appraisal well according to an embodiment of the present invention;

Figure 2 is a graph of injection rate versus time during an injection test in a series of step rate tests;

Figure 3 is a graph of pressure versus time during an injection test and a first model fit to the measured data; and

Figure 4 is a graph of fracture opening pressure and reservoir pressure versus time around an injector.

Referring initially to Figure 1, there is shown a simplified illustration of an appraisal well, generally indicated by reference numeral 10, in which an injection test is being performed. An injection test system 12 is used. The injection test system 12 comprises a string 13, being a drill pipe on which is mounted a downhole sensor 14. Though only one sensor is shown, there may be additional sensors for other measurements or for redundancy.

The sensor 14 measures pressure and temperature and sends the measured data back in real-time to a surface data acquisition and transmission unit 16 via a cable (not shown) to surface 18. Alternatively the data may be transmitted to the unit 16 by wireless telemetry. In an alternative embodiment, the data is stored in a memory on each sensor and then later analysed but this is not preferred as it does not allow real-time analysis and test program modifications based on the response of the formations. The unit 16 can also transmit the data to a remote location so off-site analysis in real-time can be performed. The sensors 14 have a sampling frequency of 1Hz. Other sampling frequencies may be used but they must be sufficient to measure changes in the pressure during the rate ramp-up and when shut-in occurs.

In Figure 1, the appraisal well 10 is shown as entirely vertical with a single formation interval 22, but it will be realised that while appraisal wells are typically vertical they can also be slightly deviated or even horizontal in rare instances. Dimensions are also greatly altered to highlight the significant areas of interest. Well 10 is drilled and completed in the traditional manner providing a casing 24 to support the borehole 26 through the length of the cap rock 28 to the location of the formation 22. Casing 24 is cemented in place and a perforated or slotted liner 19, is hung from a liner hanger 20 at the base 30 of casing 24 and extends into the borehole 26 through the formation 22. Formation 22 is a conventional oil reservoir. Other completions may also be considered such as an open-hole screen with packers for example.

At surface 18, there is a wellhead 30. Wellhead 30 provides a conduit 32 for the injection of fluids from pumps 34 into the well 10. Wellhead gauges 36 are located on the wellhead 30 and are controlled from the data acquisition unit 16 which also collects the data from the wellhead gauges 36. Wellhead gauges 36 include a temperature gauge, a pressure gauge and a rate gauge. These will also measure data. Control units may also be mounted on the surface 18 which will control the pumps 34, to vary their on/off status, temperature of the pumped fluid and flow rate of the pumped fluid. For simplification, the pumps 34 may be the cement pump already present on the rig and the fluid may be held in pits also as standard on the rig. Additional equipment in the form of a heat exchanger to vary the temperature of the fluid at surface 18 may also be present.

The injected fluid is water. This may be drill water, filtered seawater or unfiltered seawater. If desired, the water can be treated with chemicals, for example bactericide or scale inhibitors depending on predicted well characteristics obtained from core samples. A viscosifier may also be used, but it may only be required to be added if fracturing is not achieved on first injection.

For the data analysis we need to consider how to define the thermal stresses. We consider the work of T.K. Perkins and J.A. Gonzalez: 'Changes in Earth Stresses around a Wellbore Caused by Radially Symmetrical Pressure and Temperature Gradients'. SPE Journal, April, pp 129 –140, 1984 and 'The Effect of Thermoelastic Stresses on Injection Well Fracturing'. SPE Journal, February, pp 78 –88, 1985, incorporated herein by reference. Both these papers describe the changes of temperature due to injecting fluid at a constant temperature (BHT), the BHT being different from the virgin reservoir temperature (Tres). In turn the stresses are altered in the region with altered temperature. In particular the stress change ($\Delta\sigma$) is quantified by the following equation (tension negative):

$$\Delta\sigma = k\ A_T\ (BHT - Tres) \qquad \text{....(1)}$$

- k is the shape factor and Perkins and Gonzalez give formulas for a circular and an elliptical disk;
- A_T is the thermal stress parameter related to the thermo-elastic properties of the formation through:

$$A_T = a_T\ E\ /\ (1 - v) \qquad \text{....(2)}$$

- a_T is the thermal expansion of the formation
- E is Young's Modulus of the formation
- v is Poisson's ratio of the formation

This tells us that the fracture pressure around an injector will vary over time and thus the thermal stress parameter is a key factor to the design of a well injection program and the injection parameters chosen. From the perspective of hydraulic fracture propagation, injection confinement essentially depends on three main parameters:

- Water cleanliness, which can be controlled at surface but is likely to worsen due to the circulation in the lines and tubing;
- The natural stress contrast between sand and shale at the top reservoir if any exists; and
- The reduction of the fracture pressure around the injection well due to the cooling effect.

The latter of these will last throughout the life of a reservoir. However, if produced water is re-injected, its magnitude will decrease over time as more produced water is added to the injected mix. This is the case as the produced water will increase the temperature of the injected mix. If we consider injection efficiency over the years which an injection program can run, the percentage of produced water, temperature, damaging solids and oil droplets and fracture pressure all increase over the life of the well with the injectivity-risk of leakage from an injection zone also increasing for the life of the well.

Thus the time varying consequences from the thermal stress parameter mean that it is vital to quantify this parameter prior to undertaking any field development program.

To determine the thermal stress parameter we undertake injection testing at the well. Using the arrangement shown in Figure 1 we perform repeated fracture pressure measurements during step rate tests and/or fall-off analysis after injection cycles.

We will now consider an example of an Injection Test Sequence, though it must be remembered that this will be adapted for each well's situation i.e. time slot, depth, rig, etc. Adaptation to the formations encountered is also required so the drilling of the well is followed-up and deviations from the initial program are entered into the test design model. The logs are analysed to select the optimum interval to be tested (perforated). The interval should be as homogeneous as possible with respect to porosity –i.e. both stiffness and permeability. The perforation length can be revised.

A series of step rate tests with flow and shut in are performed as shown in Figure 2. For each step rate test 40a-d the water is injected at an injection rate Q 44 into the well 10 for a period of time 42 and then the well 10 is shut-in for a further period of time. Each period of injection gets progressively longer.

The step rate tests (SRT) are performed with the purpose of ensuring a clear fracturing of the formation in front of the perforated interval for each SRT. The design of the SRT is to use short steps and a large number of them (typically 5min and 100 lpm). The fracturing during the 1^{st} SRT and some other SRTs should preferably occur before surface fluid reaches the perforation, thus the wells should preferably be of sufficient depth but shallow well conditions can also be accommodated. This design essentially plays on the (BHT –Tres) term in Equation (1). A typical test duration may be 24 to 48 hours depending on the results expected with the reduced time being preferable based on rig costs.

For the injection period, the injection is constant and at a high rate. This increases the zone affected by the thermal effect during each injection cycle and thus plays on the k term in Equation (1). This injection regime also allows for the estimation of the flow properties of the reservoir during the last long injection period.

For the shut-in periods, these must be hard i.e. occur over a very brief time period. If measurements can be made in this time period, this may allow the determination of the fracture closure pressure. (square root of time, Nolte’s G-function, etc.) However, short fractures are expected and this may prove difficult to measure. As injection well testing is undertaken by shutting in the well, the shut-in period here can be used to allow characterisation of the well environment using the same factors as in standard production well testing. The shut-in further allows there to be reheating of the fluid inside the well and this can be measured.

The test is followed up and analysed in real-time either on site or remotely. The first injection cycle is analysed during its shut-in to ensure that fracturing has occurred and at which pressure/rate. If fracturing has not occurred a switch of pumps can be undertaken or the introduction of a viscosifier to increase the fluid viscosity can be considered. If it has the occurrence of a clear break-down, this must be accounted for. The second cycle may be modified based on the results of the first cycle from which modifications in the form of rate ramping schedule and duration of high rate injection can be modified. The analysis is repeated for each cycle.

Referring to Figure 3, there is illustrated a graph of the change in pressure 46 versus time 42, with the data shown as individual points 48a-f across a number of SRTs. We then fit a model 50 describing the development of the thermal stresses around the well on the measured data to estimate the thermal stress parameter. Those skilled in the art will appreciate that the fit can be a manual fit or use linear Lagrangian optimization.

To fully interpret the data we look at fracture pressure (Pfrac) against injected volume (V). Those skilled in the art will recognize that closed form solutions or numerical models can be used. In either case, the injection history (injection rate Q and bottom hole temperature BHT) is discretised: more precisely the BHT versus injected volume (V) curve is created.

For the closed form solutions, the temperature distribution in the region affected by heat convection is established; the kernel solutions provided by Perkins and Gonzalez are used in conjunction with the superposition theorem –i.e. linear problem –to compute the stress changes in the region affected by the thermal effects; and the variation over time of the fracture pressure near the well is calculated. Figure 4 shows an illustration of the measured fracture pressure 52 variation over time 42 around an injector. This is shown both in real-time 54 and by back analysis 56. This illustrates that the reservoir pressure 58, injection temperature and cold zone development all affect the fracture pressure.

For the numerical models, two solutions are possible to compute the variation of the fracture pressure around the well over time. The "classic" approach consists of using a flow model which accounts for heat convection (usually finite difference based) and then couples it with a mechanical model (usually finite element based). Alternatively a fully coupled model solving simultaneously for flow, heat transfer and mechanics can be used. However, this requires complex numerical techniques not commonly used in the oil industry –e.g. mixed element, mesh refinement, etc.

For either case a hydraulic fracture model can also be considered i.e. either a numerical model or asymptotic solutions (PKN, GdK, etc.).

Values can be incorporated into a reservoir model or other known models known to those skilled in the art from which the injection parameters can be calculated. Such injection parameters will be injection fluid temperature, fluid pump rate, fluid pump duration and fluid injection volume. These values will also provide an indication of pump requirements.

Injection testing therefore provides two main pieces of information needed for the optimum field development planning:
–The value of the large-scale thermal stress parameter for the design of the water injection system.

–Large scale flow properties of the reservoir through well test interpretation, which can be used as calibration points for the reservoir model.

Those skilled in the art will be aware that production testing i.e. Drill Stem Testing (DST) is rarely performed in appraisal wells because of the need to store the produced oil and the environment consequences of flaring the gas. Thus large scale flow of new fields is left to models. There are advantages of injection testing compared to production testing as the pumps are available on the rig and the pits to store the injected fluid are there too. The environmental impact is also limited as no hydrocarbons are produced. Additionally, by fracturing the injection well in a conventional reservoir we allow for the use of a produced water re-injection program.

The principle advantage of the present invention is that it provides a method for a well injection program in which injection testing is used to determine thermal stress characteristics of the well.

A further advantage of the present invention is that it provides a method for a well injection program in which injection testing is used to determine parameters for well interpretation.

The foregoing description of the invention has been presented for the purposes of illustration and description and is not intended to be exhaustive or to limit the invention to the precise form disclosed. The described embodiments were chosen and described in order to best explain the principles of the invention and its practical application to thereby enable others skilled in the art to best utilise the invention in various embodiments and with various modifications as are suited to the particular use contemplated.

Therefore, further modifications or improvements may be incorporated without departing from the scope of the invention herein intended.

CLAIMS

1. A method for a well injection program, comprising the steps:
   (a) selecting an appraisal well;
   (b) selecting a perforation interval and length;
   (c) locating at least one downhole sensor to measure pressure in the well;
   (d) injecting a fluid into the well;
   (e) varying the flow rate of injected fluid;
   (f) measuring the pressure with flow rate variations to provide measured data;
   (g) fitting a first model to the measured data to estimate a thermal stress characteristic of the well;
   (h) inputting the thermal stress characteristic into a second model; and
   (i) determining injection parameters from the second model.

2. A method according to claim 1 wherein the method includes the steps of performing a series of step rate tests and measuring fracture pressure.

3. A method according to claim 1 wherein the method includes the steps of performing injection cycling and fall-off analysis.

4. A method according to any preceding claim wherein the first model describes the development of the thermal stresses around the well on the measured data to estimate a thermal stress characteristic.

5. A method according to any preceding claim wherein the thermal stress characteristic is a thermal stress parameter.

6. A method according to any preceding claim wherein the second model is a reservoir model.

7. A method according to any preceding claim wherein the second model is a hydraulic fracture model.

8. A method according to any preceding claim wherein the at least one downhole sensor also measures temperature.

9. A method according to any preceding claim wherein the downhole sensors data sampling rate is 1 Hz or greater.

10. A method according to any preceding claim wherein the downhole sensors transmit data to the surface in real-time.

11. A method according to claim 10 wherein the downhole sensors transmit data to the surface via a cable.

12. A method according to claim 10 wherein the downhole sensors transmit data to the surface by telemetry.

13. A method according to any preceding claim wherein the downhole sensors include memory gauges on which the measured data is stored.

14. A method according to any preceding claim wherein the method includes the step of measuring pressure for different temperatures of injected fluid.

15. A method according to any preceding claim wherein pressure, temperature and flow rate are measured at the surface of the well.

16. A method according to any preceding claim wherein the method includes the step of measuring the pressure and flow rate during a first injection cycle and determining fracturing has occurred.

17. A method according to claim 16 wherein parameters for the second injection cycle are determined from the first injection cycle.

18. A method according to claim 17 wherein the step is repeated for further injection cycles.

19. A method according to any preceding claim wherein the injected fluid is water.

20. A method according to claim 19 wherein the injected fluid is selected from a group comprising: drill water, filtered seawater or unfiltered seawater.

21. A method according to claim 19 or claim 20 wherein the injected fluid is chemically treated.

22. A method according to any one of claim 20 to 22 wherein the injected fluid includes a viscosifier.

23. A method according to any preceding claim wherein the appraisal well has a well completion.

24. A method according to claim 24 wherein the well completion is with a cemented and perforated liner over an interval.

25. A method according to any preceding claim wherein the downhole sensors are run in the well on a string.

26. A method according to any preceding claim wherein the well injection parameters are selected from a group comprising: injection fluid temperature, fluid pump rate, fluid pump duration and fluid injection volume.

27. A method according to any preceding claim wherein the method includes the further step of carrying out well injection using the well injection parameters.

1/2

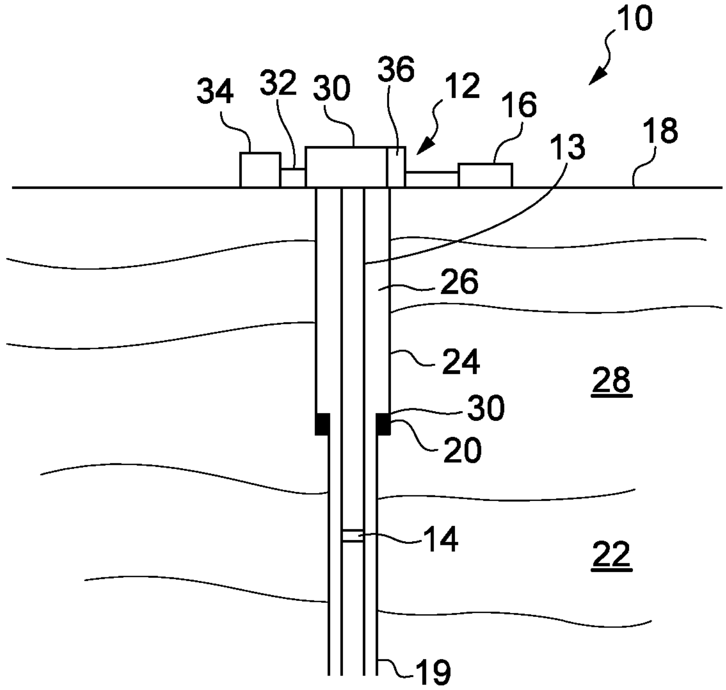

10
34
32
30
36
12
16
13
18
26
24
28
30
20
14
22
19

Fig. 1

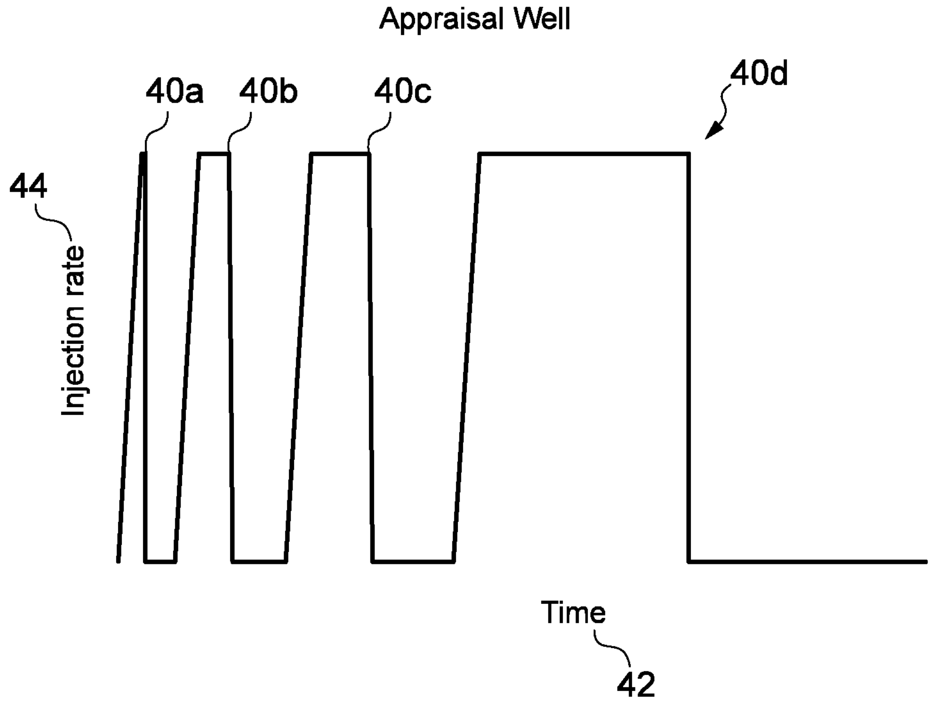
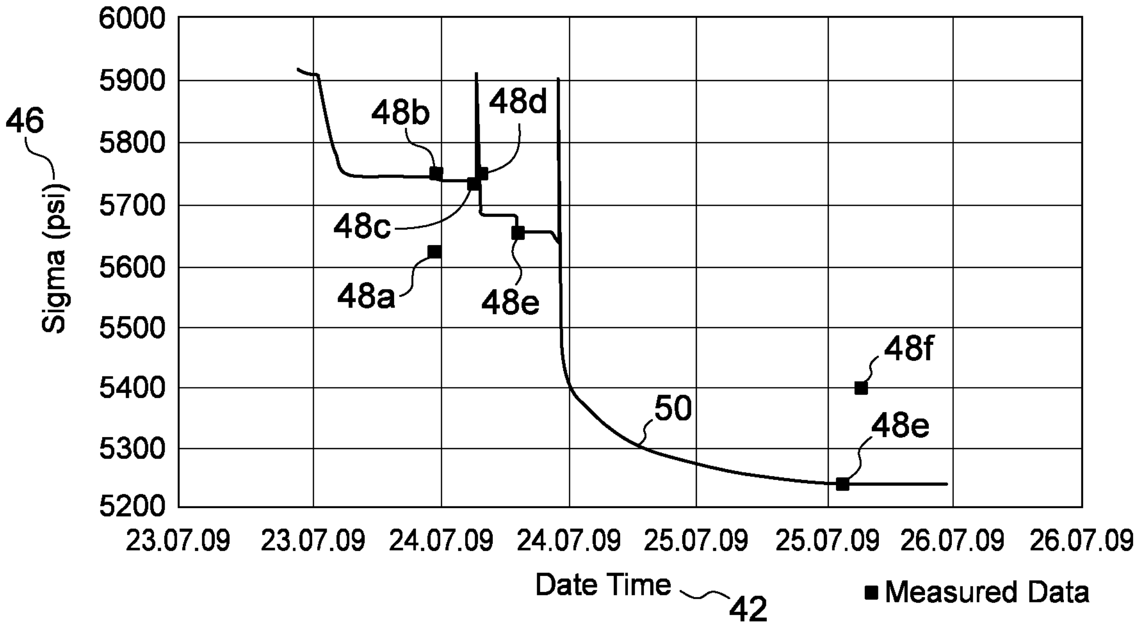
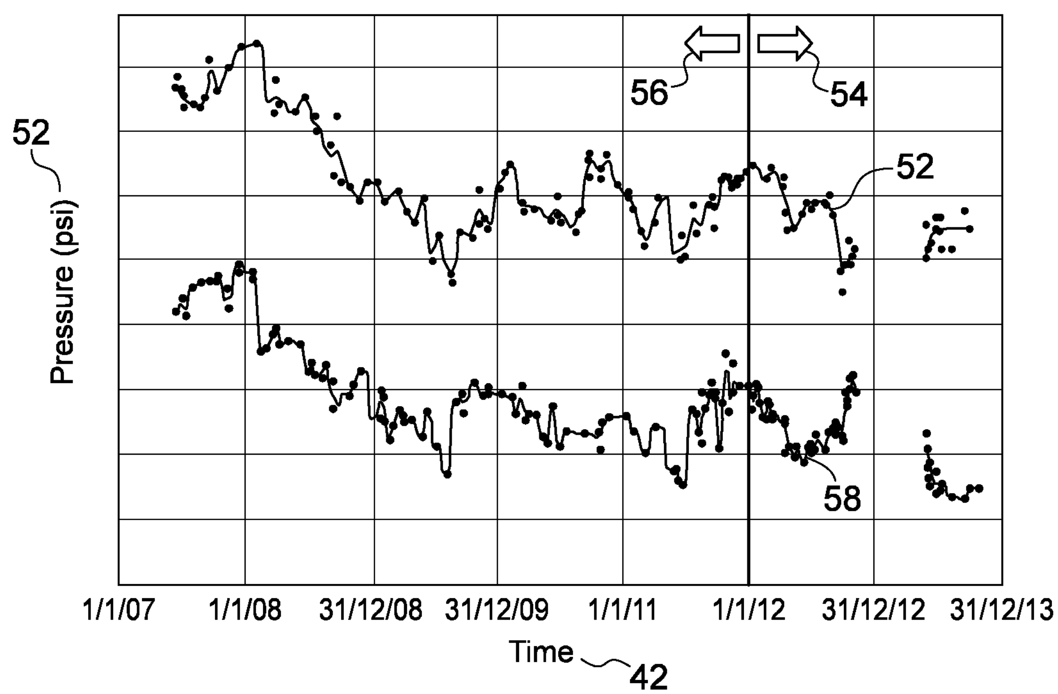

Appraisal Well
40a
40b
40c
40d
44
Injection rate
Time
42

Fig. 2



6000
5900
5800
5700
5600
5500
5400
5300
5200
46
Sigma (psi)
48a
48b
48c
48d
48e
48f
50
23.07.09
23.07.09
24.07.09
24.07.09
25.07.09
25.07.09
26.07.09
26.07.09
Date Time
42
Measured Data

Fig. 3



52
Pressure (psi)
56
54
52
58
1/1/07
1/1/08
31/12/08
31/12/09
1/1/11
1/1/12
31/12/12
31/12/13
Time
42

Fig. 4

INTERNATIONAL SEARCH REPORT

International application No
PCT/GB2018/051394

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B49/00 E21B47/06
ADD.

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

B. FIELDS SEARCHED

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

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

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

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2015/126388 A1 (HALLIBURTON ENERGY SERVICES INC [US]; PETRO RES & ANALYSIS CORP [US]) 27 August 2015 (2015-08-27)	1,19-22, 27
Y	page 3, line 5 - page 5, line 9; figures 1,2	2,3, 15-18,26
A	page 11, lines 15-21 -----	14
Y	WO 2016/099470 A1 (HALLIBURTON ENERGY SERVICES INC [US]) 23 June 2016 (2016-06-23) page 9, lines 4-11; claims 1-16; figures 3-7 -----	2,3, 15-18,26

-/--

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

[X] See patent family annex.

* Special categories of cited documents :

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

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

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"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	Date of mailing of the international search report
24 August 2018	09/11/2018

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

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	T.K. PERKINS ET AL: "Changes in Earth Stresses Around a Wellbore Caused by Radially Symmetrical Pressure and Temperature Gradients", SOCIETY OF PETROLEUM ENGINEERS JOURNAL, vol. 24, no. 02, 1 April 1984 (1984-04-01), pages 129-140, XP055501505, US ISSN: 0197-7520, DOI: 10.2118/10080-PA cited in the application the whole document -----	1-3, 14-22, 26,27
A	T.K. PERKINS ET AL: "The Effect of Thermoelastic Stresses on Injection Well Fracturing", SOCIETY OF PETROLEUM ENGINEERS JOURNAL, vol. 25, no. 01, 1 February 1985 (1985-02-01), pages 78-88, XP055501512, US ISSN: 0197-7520, DOI: 10.2118/11332-PA cited in the application the whole document -----	1-3, 14-22, 26,27
A	US 2005/222852 A1 (CRAIG DAVID P [US]) 6 October 2005 (2005-10-06) paragraphs [0011] - [0037] -----	1-3, 14-22, 26,27

INTERNATIONAL SEARCH REPORT

International application No.
PCT/GB2018/051394

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.:
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:

see additional sheet

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 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.:

1-3, 14-22, 26, 27

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.

FURTHER INFORMATION CONTINUED FROM PCT/ISA/ 210

This International Searching Authority found multiple (groups of) inventions in this international application, as follows:

1. claims: 1-3, 14-22, 26, 27

   A method of a well injection program injecting fluid into the well while varying a flow rate of the injected fluid and modelling the injection parameters, where an injection schemes such as fracturing test, injection cycling, fall-off analysis, measuring flow rate, temperature and pressure during injection cycles while injection water with or without chemicals/additives.

   ---

2. claims: 4-7

   A method of a well injection program injecting fluid into the well while varying a flow rate of the injected fluid and modelling the injection parameters wherein the several models are further defined as thermal stress development model, reservoir model and hydraulic fracture model.

   ---

3. claims: 8-13, 25

   A method of a well injection program injecting fluid into the well while varying a flow rate of the injected fluid and modelling the injection parameters with a plurality of sensors at various locations are defined to provide measurement data during the well injection program.

   ---

4. claims: 23, 24

   A method of a well injection program injecting fluid into the well while varying a flow rate of the injected fluid and modelling the injection parameters defining a well completion and well perforation set-up.

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/GB2018/051394

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
WO 2015126388 A1	27-08-2015	CA 2936351 A1	27-08-2015
		US 2016230547 A1	11-08-2016
		WO 2015126388 A1	27-08-2015
WO 2016099470 A1	23-06-2016	CA 2959593 A1	23-06-2016
		US 2017275990 A1	28-09-2017
		WO 2016099470 A1	23-06-2016
US 2005222852 A1	06-10-2005	AR 050061 A1	27-09-2006
		AU 2005229229 A1	13-10-2005
		BR PI0509251 A	11-09-2007
		CA 2561256 A1	13-10-2005
		GB 2426349 A	22-11-2006
		US 2005222852 A1	06-10-2005
		WO 2005095756 A1	13-10-2005